Cost Estimates for Selected Applications of NO$_x$ Control Technologies on Stationary Combustion Boilers

Draft Report, March 1996

## and

Responses to Comments on the Draft Report

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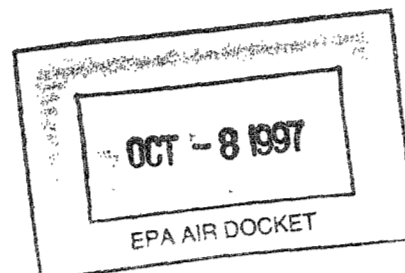
COST ESTIMATES FOR SELECTED APPLICATIONS OF NO$_X$ CONTROL TECHNOLOGIES ON STATIONARY COMBUSTION BOILERS

Draft Report

March 1996

Prepared for

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COST ESTIMATES FOR NO$_x$ CONTROL TECHNOLOGIES

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1.0 PROJECT OVERVIEW

This report presents the results of a study conducted by Bechtel to develop costs for NO_x control technologies for coal-, gas-, and oil-fired boilers. The types of boilers for each fuel along with the size range and baseline NO_x emission rate for each boiler type were identified by the United States Environmental Protection Agency (EPA), as shown in Table 1-1.

The technical and economic evaluations conducted for this study used a consistent methodology to develop costs for various NO_x control technology applications. The costs are therefore comparable between different boiler types and sizes.

1.1 Project Purpose

The primary objectives of this study were to:

- Develop costs for the NO_x control technologies with a capability to reduce NO_x emission from the baseline NO_x rate to 0.15 lb/MMBtu for each study boiler

- Develop costs for the NO_x control technologies with a capability to provide substantial NO_x emission reductions for the dry-bottom tangential and wall-fired boilers burning coal beyond those required under 40 CFR Part 76

1.2 Major Results

The capital and levelized costs for each technology case are presented in the figures that are included at the end of this report. The major costs from these figures are summarized in the following tables:

- Table 1-2 presents the fixed and variable costs for a 200 MW boiler for each technology application. The variable costs are reported for both the 27 and 65 percent capacity factors. Two types of variable costs have been included: one containing the carrying charges for the capital expenditure and the other without this carrying charge (as reported in EPRI's TAG). In addition, Table 1-2 also provides a mathematical relationship to facilitate estimation of the capital cost for a given boiler size (MW).

- Tables 1-3 and 1-4 present the capital ($/kW) and levelized ($/ton of NO_x removed) costs for two selected sizes of boiler installations for each NO_x control technology (for both 0.15 lb/MMBtu and substantial reduction cases). These costs are reported for both the 27 and 65 percent capacity factors. Also provided are references to the figures from which these costs have been obtained.

1.3 General Approach to Technical and Cost Analyses

The overall approach for both the technical and cost analyses was based primarily on the methodology utilized in a previous Bechtel study that involved evaluation of NO_x control tech-

nologies for the Group 2 boilers. A copy of the previous study is provided as Appendix A to this report.

The major elements of the project approach and the areas where the approach differs from the previous study are as follows:

- An evaluation of the commercially available NO_x control technologies was made to determine feasibility for meeting the aforementioned project objectives. Table 1-5 lists these technologies along with their NO_x reduction effectiveness and applicability to each study boiler type. The data presented in Table 1-5 were based on published information on a variety of technology applications (References 1 through 17).

   Based on the above evaluation, the following technologies are considered in this report:

   ◆ The selective catalytic reduction (SCR) technology was selected for its capability to provide NO_x reduction to the 0.15 lb/MMBtu limit for all study boilers. For the oil- and gas-fired boilers, both the selective noncatalytic reduction (SNCR) and gas reburning technologies were also selected for the same purpose.

   ◆ The SNCR, gas reburning, and coal reburning technologies have been found to have a capability to provide substantial NO_x reduction for the tangential and wall-fired boilers burning coal. Of these, the SNCR technology was selected for evaluation for this project. Costs of gas and coal reburning applications on Group 2 boilers have been examined in detail in the previous Bechtel study (Appendix A).

- The technical and economic evaluations were conducted on representative boiler installations for each boiler category identified for this project. The design data for the representative boiler installations were developed from Bechtel's in-house database.

- Both capital costs ($/kW) and levelized costs (mils/kWh and $/ton NO_x removed) were developed for the applicable boiler size range for each technology application.

- The capital cost estimates were developed by factoring from the 1994 cost data generated in the previous Bechtel study (Appendix A) for each NO_x control technology. The new estimates were not based on detailed major equipment lists, as developed in the previous study. Instead, appropriate power factors representing the general industry practice were applied to the existing costs to obtain costs for this project. This method took into consideration the differences in the overall system size and capacity between each technology application for this project and the corresponding application in the previous study.

- All new costs were developed in 1995 dollars. The latest available Chemical Engineering cost index for September 1995 was used to adjust the estimated 1994 costs to 1995.

- The levelized costs were based on the economic factors reported in the 1993 EPRI TAG (Reference 18). They were developed using a constant dollar approach. Other economic assumptions were the same as shown in Appendix A and detailed in Section 2.0.

- All levelized costs were developed based on the following operating modes:

  - The NO_x control technology in operation for the entire 12-month period with a capacity factor of 65 percent

  - The NO_x control technology in operation for 5 months in a year with a capacity factor of 65 percent (resulting in an effective yearly capacity factor of approximately 27 percent).

1.4 Clarifications

Note that alternate technologies other than those selected in this study may also be applied to achieve the study objectives. For instance, a combination of some of the technologies, such as hybrid SCR/SNCR, can be used for this purpose. However, these alternatives are beyond the scope of the study. Additionally, this study does not imply that NO_x emissions from every boiler in the populations considered can be controlled to a 0.15 lb/MMBtu level; some boilers may be controlled to levels higher than 0.15 lb/MMBtu and others to levels lower than 0.15 lb/MMBtu.

TABLE 1-1

STUDY BOILERS AND BASELINE NO$_X$ EMISSIONS[1]

Boiler Type	Size Range, MW	Fuel	Baseline NO$_X$ Rate lb/MMBtu
Dry bottom, wall-fired	30-1300	Coal Gas Oil	0.50 (Title IV limit) 0.25 0.30
Dry bottom, tangentially fired	33-952	Coal Gas Oil	0.45 (Title IV limit) 0.25 0.30
Cell	200-1300	Coal	0.8-1.5 (1.00 average)
Cyclone	25-1200	Coal	0.8-1.9 (1.17 average)
Wet bottom	25-800	Coal	0.7-1.7 (1.13 average)
Dry bottom, vertically fired	25-300	Coal	0.85-1.1 (1.08 average)

NOTE

1. For Group 1 boilers, the baseline NO$_X$ rates are the currently allowable emission limitations under 40 CFR Part 76. For Group 2 boilers, the baseline NO$_X$ rates represent the average uncontrolled NO$_X$ rates, per boiler type, as presented in Appendix A to "Investigation of Performance and Cost of NO$_X$ Controls as Applied to Group 2 Boilers," August 1995, prepared for the U.S. EPA.

TABLE 1-2

CAPITAL AND O&M COSTS[1], [2], [3]

Case[4]	Capital Cost ($)	Fixed Cost for 200 MW	Variable Cost for 200 MW w/o Capital 65% Capacity Factor	Variable Cost for 200 MW (w/o Capital) 27% Capacity Factor	Variable Cost for 200 MW (w/Capital) 65% Capacity Factor	Variable Cost for 200 MW (w/Capital) 27% Capacity Factor
COAL- TANGEN- SCR	$66.824*(200/MW)^{0.35}$	1	1.04	2.2	2.53	5.78
COAL-TANGEN-SNCR	$15.551*(200/MW)^{0.577}$	0.23	0.99	0.99	1.34	1.82
COAL- WALL- SCR	$69.382*(200/MW)^{0.35}$	1.04	1.11	2.33	2.66	6.05
COAL-WALL-SNCR	$17.511*(200/MW)^{0.577}$	0.26	1.02	1.02	1.41	1.95
COAL- CELL- SCR	$69.217*(200/MW)^{0.324}$	1.04	1.35	2.67	2.89	6.38
COAL- CYCLONE- SCR	$69.55*(200/MW)^{0.261}$	1.04	1.38	2.72	2.93	6.44
COAL- WET BOTTOM- SCR	$70.571*(200/MW)^{0.296}$	1.06	1.41	2.76	2.98	6.54
COAL- VERT-FIRED- SCR	$67.067*(200/MW)^{0.391}$	1.01	1.33	2.6	2.83	6.19
GAS-SCR	$27.483*(200/MW)^{0.35}$	0.41	0.17	0.28	0.79	1.75
GAS- REBURN	$19.025*(200/MW)^{0.357}$	0.29	0.03	0.03	0.45	1.04
GAS- SNCR	$9.433*(200/MW)^{0.577}$	0.14	0.42	0.42	0.63	0.92
OIL- SCR	$39.975*(200/MW)^{0.35}$	0.6	0.36	0.7	1.25	2.84
OIL- REBURN	$22.298*(200/MW)^{0.357}$	0.34	0.51	0.51	1.01	1.7
OIL- SNCR	$10.638*(200/MW)^{0.577}$	0.16	0.58	0.58	0.82	1.15

NOTES

1. Fixed costs are reported in $/kW-yr. The variable costs are reported in mil/kWh.
2. The variable costs are reported both with and without the carrying charges for the capital costs. As per the EPRI's TAG, the variable costs do not include carrying charges. Also, for this report, the costs associated with the changes in the fuel consumption rates because of the retrofit have been included in the variable costs. EPRI does not include fuel costs in the variable cost component.
3. The capacity factor reflects the annual usage for which the NO_x control technology is in operation.
4. Where the boiler firing type is not mentioned, the case applies to both the wall-fired and tangentially fired boilers.

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TABLE 1-3

SUMMARY OF RESULTS
NO$_x$ CONTROL TECHNOLOGIES ACHIEVING 0.15 LB/MMBTU LIMIT

Boiler[1]	Fuel	NO$_x$ Control	Boiler Size, MW	65% Capacity Factor[2]		27% Capacity Factor[2]		Figures[3]
				$/kW	$/Ton	$/kW	$/Ton	
TN	Coal	SCR	200	66.82	1935	66.82	4427	3-1,3,5
			930	39.02	1439	39.02	3238	
WF	Coal	SCR	200	69.38	1670	69.38	3815	3-11,13,15
			1030	39.1	1226	39.1	2748	
CELL	Coal	SCR	200	69.22	801	69.22	1775	3-21,23,25
			1030	40.7	624	40.7	1351	
CYC	Coal	SCR	200	69.55	695	69.55	1536	3-26,28,30
			1030	45.34	536	45.34	1125	
WB	Coal	SCR	200	70.57	733	70.57	1616	3-31,33,35
			730	48.07	572	48.07	1231	
VF	Coal	SCR	70	101.11	907	101.11	2032	3-36,38,40
			200	67.07	750	67.07	1654	

NOTES

1. The legend for the symbols used is:
   - CYC   Cyclone-fired
   - TN   Tangential
   - VF   Vertically fired, dry bottom
   - WF   Wall-fired, dry bottom
   - WB   Wet bottom
2. The capacity factor reflects the annual duration for which the NO$_x$ technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

TABLE 1-3 (Continued)

Boiler[1]	Fuel	NOₓ Control	Boiler Size, MW	65% Capacity Factor[2]		27% Capacity Factor[2]		Figures[3]
				$/kW	$/Ton	$/kW	$/Ton	
WF, TN	Gas	SCR	200	27.48	2142	27.48	4802	4-1,3,5
			930	16.05	1429	16.05	3091	
WF, TN	Gas	Reburn	200	19.03	1250	19.03	2910	4-6,8,10
			930	10.99	748	10.99	1706	
WF,TN	Gas	SNCR	200	9.43	1632	9.43	2455	4-11,13,15
			930	3.66	1272	3.66	1592	
WF, TN	Oil	SCR	200	39.98	2263	39.98	5151	5-1,3,5
			930	23.34	1571	23.34	3492	
WF, TN	Oil	Reburn	200	22.30	1776	22.30	3073	5-6,8,10
			930	12.88	1384	12.88	2122	
WF,TN	Oil	SNCR	200	10.63	1407	10.63	2026	5-11,13,15
			930	4.38	1147	4.38	1402	

NOTES

1. The legend for the symbols used is:
   CYC   Cyclone-fired
   TN   Tangential
   VF   Vertically fired, dry bottom
   WF   Wall-fired, dry bottom
   WB   Wet bottom
2. The capacity factor reflects the annual duration for which the NOₓ technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

TABLE 1-4

SUMMARY OF RESULTS
COST OF SNCR APPLICATIONS ON DRY-BOTTOM WALL- AND
TANGENTIALLY FIRED BOILERS

Boiler[1]	Fuel	NO$_x$ Control	Boiler Size, MW	65% Capacity Factor[2]		27% Capacity Factor[2]		Figures[3]
				$/kW	$/Ton	$/kW	$/Ton	
TN	Coal	SNCR	200	15.55	1378	15.55	1921	3-6,8,10
			930	6.41	1150	6.41	1377	
WF	Coal	SNCR	200	17.51	1210	17.51	1720	3-16,18,20
			1030	6.80	988	6.80	1186	

NOTES

1. The legend for the symbols used is:
   TN   Tangential
   WF   Wall-fired, dry bottom
2. The capacity factor reflects the annual duration for which the NO$_x$ technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

TABLE 1-5

APPLICABLE NO$_x$ CONTROL TECHNOLOGIES

Technology	NO$_x$ Reduction Effectiveness	Boiler Applications[1]	Primary Fuel[1]
Combustion Controls[2]	40 - 70%	WF, TN, Cell, WB, VF	C, O, G
Coal Reburning	35 -50%	WF, TN, Cell, CYC WB, VF	C
Gas Reburning	40 -60%	WF, TN, Cell, CYC WB, VF	C, O, G
Selective Catalytic Reduction	80 - 90%	WF, TN, Cell, CYC WB, VF	C, O, G
Selective Non-catalytic Reduction	30 - 50%	WF, TN, Cell, CYC WB, VF	C, O, G

NOTES

1. The legend for symbols used is:

    C   Coal
    O   Oil
    G   Gas
    WF   Wall-fired dry bottom
    TN   Tangential
    CYC   Cyclone-fired
    WB   Wet bottom
    VF   Vertically fired, dry bottom

2. Combustion controls include low-NO$_x$ burners, overfire air, and gas recirculation (for oil or gas boilers only).

2.0 METHODOLOGY AND GENERAL ASSUMPTIONS

The methodology and assumptions used in selecting the applicable NO_x control technologies and conducting the technical and economic evaluations for this project are detailed in this section.

2.1 Technology Selections

Table 1-2 categorized the commercially available technologies and their NO_x control potential for various boiler types. As shown in this table, the NO_x reduction effectiveness varies depending on the site-specific conditions for any given application.

The study criteria define the baseline NO_x rates for the dry-bottom wall-fired and tangential boilers burning coal to be 0.45 and 0.5 lb/MMBtu, respectively (these rates being required by 40 CFR Part 76). The baseline NO_x rates for the same boilers on oil and gas are defined as 0.3 and 0.25 lb/MMBtu, respectively, because these rates currently are being achieved on gas- and oil-fired boilers. It is assumed that these NO_x rates correspond to boilers equipped with low-NO_x burners only (no overfire air ports).

The above assumption implies that full credit can be taken for the NO_x reduction potential of the technologies (such as gas reburning) utilizing overfire air ports. Without this assumption, application of these technologies to boilers with existing overfire air ports would be possible only if the ports are replaced with the new ports associated with the technologies. Deletion of the existing ports would have a corresponding impact of increasing the baseline NO_x levels, thus requiring a higher NO_x reduction to achieve 0.15 lb/MMBtu.

As per the study criteria, the NO_x reduction efficiencies required to meet the 0.15 lb/MMBtu for the gas- and oil-fired boilers are 40 and 50 percent, respectively. For coal-fired boilers, these efficiencies range from 66.67 to 87.18 percent.

Based on the above background information and assumptions, assessment of the feasibility of applying various technologies to the study boilers is as follows:

- The various components of combustion controls include low-NO_x burners, overfire air ports, and gas recirculation fans. Where applicable, the study boilers are already equipped with low-NO_x burners. Since these burners reflect a major portion of the overall effectiveness of combustion controls, installation of other technology components on these boilers to achieve 0.15 lb/MMBtu does not appear possible.

- The coal reburning technology is not feasible for application on any coal-fired study boiler, since the minimum required NO_x reduction efficiency of 66.67 percent is still higher than the maximum potential of this technology (50 percent reduction).

- The gas reburning technology can provide a NO_x reduction ranging from 40 to 60 percent. Since the reductions to achieve the 0.15 lb/MMBtu level for the gas- and oil-fired boilers fall within this range, this technology is considered to be a suitable candidate for these boilers. It is to be recognized that site-specific factors for some plants may pose serious constraints

either to achieve proper NO_x reductions or to install the technology components. These factors include lack of sufficient space to install the reburn fuel injectors (or burners) and overfire air ports, lack of proper residence times, and unavailability of natural gas.

- The effectiveness of the SNCR technology can vary from 30 to 50 percent. Based on the NO_x reduction needs (0.15 lb/MMBtu) of the study boilers, this technology can be applied only to the gas- and oil-fired boilers. Similar to gas reburning, this feasibility may be subject to site-specific factors. The most important aspect of SNCR is the availability of a proper residence time within the boiler in a required temperature zone, which varies with the type of SNCR system used (ammonia- or urea-based). It is recognized that such residence times may not be available in all gas- and oil-fired boilers.

- The NO_x reduction needs of all study boilers fall within the potential effectiveness range (80 to 90 percent) for the SCR technology, which is therefore considered feasible for all of these boilers.

  Even for the SCR technology, the NO_x reduction rates required for the cell, cyclone, wet bottom, and vertically fired boilers are relatively high. Such rates would require significantly large amounts of catalyst. Other concerns, such as excessive SO_3 conversion rates, may also be applicable in some specific retrofits.

  In some cases, the duty on the SCR systems could be reduced by applying more than one NO_x control technology. For instance, hybrid systems using SNCR and SCR could be used, or SCR could be applied with combustion controls (applicable to cell, wet bottom, and vertically-fired boilers). These applications are considered outside the scope of the study.

- Based on the above analyses, the technologies selected for meeting the 0.15 lb/MMBtu limit include SCR for all boiler categories and SNCR and gas reburning for gas- and oil-fired boilers only. Similarly, SNCR has been considered for achieving substantial NO_x reduction (50 percent) for the wall-fired and tangential boilers burning coal.

2.2 Technical Evaluations

The methodology for the technical evaluations is essentially the same as used in the previous study (Appendix A, Section 2.0 of Appendix B). The highlights of this methodology are as follows:

- All design details pertaining to the representative boilers in the cyclone, cell, wet-bottom, and vertically fired categories are the same as shown in the previous study.

- Since the tangential and wall-fired boilers burning coal, oil, or gas were not included in the previous study, design details of representative boilers for these categories have been specifically developed for this project from the Bechtel in-house database. In the case of each boiler category, the evaluations are performed using one representative boiler. It is assumed that boiler design parameters vary in a direct proportion to the boiler size.

- The design and performance impacts of each technology application have been based on the same assumptions as used in the previous study (Appendix A).

2.3 Economic Evaluations

Similar to the technical evaluations, the methodology in the previous study (Appendix A, Section 2.0 of Appendix B) has been utilized in most parts in conducting the economic evaluations for this project. The major areas of differences are as follows:

- The costs for this study are in 1995 dollars compared to the 1990 dollars used in the previous study. Because of this difference, the economic factors provided in Table B2-2 of Appendix A have been revised for use in this study.

  Table 2-1 shows the revised economic factors. The highlights of these revisions are described below:

  - The 1993 EPRI TAG has been used for establishing the carrying charge factor, levelization factor, costs of consumables (ash and water), and cost of operating labor.

  - The 1993 EPRI TAG shows a decline in the coal price from 1990 to 1995 period. For conservatism, the 1990 coal price is used. Since the only study cases where coal consumption is affected are the tangential and wall-fired boilers firing bituminous coals, only the bituminous coal price is shown.

  - The No. 6 oil and natural gas prices are based on a recent publication (Reference 19), which is considered more current than the data presented in EPRI TAG.

  - The SCR catalyst replacement costs and the SO_2 allowance are assumed to be the same as reported for the previous study.

  - The urea and anhydrous ammonia costs are revised to reflect the 1995 costs reported in Appendix A, Section C.2.

- For the tangential and wall-fired boilers, the costs have been developed using data for one representative boiler. In establishing the costs for the boiler size range, it is assumed that performance parameters vary in direct proportion to the boiler size. The capital costs for the boiler size range have been developed by using the scaling methodology described in Section 2.4.1 of Appendix A. The same scaling factors have been used as determined for the various technology cases evaluated in Appendix A.

- The capital costs have been adjusted to the study reference period by using the Chemical Engineering cost index for September 1995.

- All levelized costs have been developed based on the following plant operating modes:

  - The NO_x control technology in operation for the entire 12-month period with a capacity factor of 65 percent

  - The NO_x control technology in operation for 5 months in a year with a capacity factor of 65 percent (resulting in an effective yearly capacity factor of approximately 27 percent)

TABLE 2-1

ECONOMIC FACTORS

Parameter	Value
Cost year	September 1995
Useful life	20 years
Carrying charges	0.127
Levelization factor	1.0
Maintenance cost	1.5% (of capital)/year
Electrical power cost	$0.05/kWh
Bituminous coal cost	$1.60/MMBtu
Natural gas cost	$2.27/MMBtu
No. 6 oil cost	$1.97/MMBtu
Ash disposal cost	$11.28/ton
Anhydrous ammonia cost	$202/ton
Urea cost (50% solution)	$0.80/gallon
SCR catalyst replacement cost	$350/ft^3
Operator cost	$24.82/person-hour
Water cost	$0.0004/gallon
SO_2 allowance	$150/ton

3.0 COAL-FIRED PLANT ASSUMPTIONS AND RESULTS

This section summarizes the technical and economic evaluations conducted for the coal-fired boiler applications of NO_x control technologies.

3.1 Tangential Boiler Applications

The NO_x control technologies evaluated for this boiler type include SCR and SNCR. The design data for the representative boiler selected for this evaluation are shown in Table 3-1. This boiler is a balanced draft, forced circulation, reheat, single furnace boiler. It has four windboxes located along the four corners of the furnace. There are a total of 20 coal burners, five per corner. The boiler serves a 348 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

3.1.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the coal-fired tangential boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.45 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Anhydrous ammonia is utilized as a reagent for the SCR system.

- The system is designed for an ammonia slip of 5 ppm.

- A 14-day storage is provided at the plant site for anhydrous ammonia. This storage capacity is based on a full-load operation of the boiler.

- It is assumed that the existing plant setting allows installation of the SCR reactors between the economizer and air heater without a need to relocate any major structure or equipment.

- The operating life of the SCR catalyst is assumed at 3 years. A catalyst life management strategy is not used for this evaluation. It is also assumed that no appreciable difference in the catalyst life occurs when the plant is operated at low capacity factors. This assumption results in conservative cost estimates, since it is expected that a low-capacity factor may result in a net catalyst life increase.

- Other general SCR system design details, assumptions, and impacts on the existing equipment outlined in Appendix A (Section 4.5 of Appendix B) also apply to this case.

The SCR technology is a postcombustion technology, in which the reagent is injected into the flue gas stream at the economizer outlet upstream of the catalyst reactor. As such, SCR technology has no direct impact on the boiler performance. The boiler parameters shown in Table 3-1 would remain unchanged following a SCR retrofit. However, such a retrofit would impact

the plant's overall operating costs, because of the increased auxiliary power consumption, anhydrous ammonia usage, and periodic catalyst replacement. For the study boiler, estimates of these consumables associated with the SCR system are as follows:

Auxiliary power consumption	768 kW
Anhydrous ammonia consumption	365 lb/hr
Average catalyst replacement	4,680 ft^3/yr

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (33 to 952 MW) of tangential, coal-fired boilers. As shown in Figure 3-1, the capital costs range from approximately $35 to $130/kW. The levelized costs at a capacity factor of 65 percent range from 1.9 to 4.3 mils/kWh and $1,240 to $3,050/ton NO_x removed (Figures 3-2 and 3-3). The levelized costs at a capacity factor of 27 percent range from 4.25 to 9.9 mils/kWh and $3,100 to $7,100/ton NO_x removed (Figures 3-4 and 3-5).

3.1.2 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the coal-fired, tangential boilers:

- The SNCR system is designed to provide a 50 percent NO_x reduction from a baseline NO_x rate of 0.45 lb/MMBtu.

- A urea-based SNCR technology is selected for this application.

- The system is designed for an ammonia slip of 10 ppm, selected to minimize impacts on the equipment located downstream of the boiler (air heater, precipitator, etc.). Higher ammonia slip may produce ammonium salts causing pluggage of air heater and contamination of ash collected in the precipitator.

- A 14-day storage based on a full-load operation is provided at the plant site for the urea solution.

- For an effective reaction between the reagent and NO_x, sufficient residence times must exist within the boiler in a proper temperature zone (1,800 to 2,000 °F). It is assumed that such residence times are available within the boilers being evaluated. It is to be noted that without adequate residence times, it may not be possible to achieve a 50 percent NO_x reduction while maintaining the ammonia slip at 10 ppm.

- A reagent ratio of 1.75 is selected for the SNCR system design.

- Other general SNCR system design details, assumptions, and impacts on the existing equipment outlined in Appendix A (Section 4.4 of Appendix B) also apply to this case.

Injection of the urea solution within the boiler does have an impact on the boiler performance, because of the heat loss associated with the moisture content of this solution. This heat loss causes a slight reduction in the boiler efficiency, resulting in increased fuel flow, ash generation, and combustion air and flue gas flow rates. The overall impacts of the SNCR system retrofit on the study boiler are as follows:

- The boiler efficiency reduces from 88.39 to 88.00 percent. The boiler heat input increases from 3,210 to 3,244 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 157 kW.

- The urea consumption requirement for the SNCR system is 350 gal./hr.

- The water consumption requirement for the SNCR system is 4,470 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (33 to 952 MW) of tangential, coal-fired boilers. As shown in Figure 3-6, the capital costs range from approximately $6 to $46/kW. The levelized costs at a capacity factor of 65 percent range from 1.13 to 2.15 mils/kWh and $1,140 to $2,130/ton NO_x removed (Figures 3-7 and 3-8). The levelized costs at a capacity factor of 27 percent range from 1.32 to 3.78 mils/kWh and $1,330 to $3,800/ton NOx removed (Figures 3-9 and 3-10).

3.2 Wall-Fired Boiler Applications

The NO_x control technologies evaluated for this boiler type include SCR and SNCR. The design data for the representative boiler selected for this evaluation are shown in Table 3-1. This boiler is a balanced draft, natural circulation, reheat, single furnace boiler. It has 24 burners located four high and six wide on the front wall of the unit. The boiler serves a 381 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

3.2.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.5 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boiler are as follows:

Auxiliary power consumption	842 kW
Anhydrous ammonia consumption	476 lb/hr
Average catalyst replacement	5417 ft³/yr

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (30 to 1,300 MW) of wall-fired boilers. As shown in Figure 3-11, the capital costs range from approximately \$37 to \$134/kW. The levelized costs at a capacity factor of 65 percent range from 2.03 to 4.5 mils/kWh and \$1,180 to \$2,600/ton NO_x removed (Figures 3-12 and 3-13). The levelized costs at a capacity factor of 27 percent range from 4.5 to 10.4 mils/kWh and \$2,700 to \$6,100/ton NO_x removed (Figures 3-14 and 3-15).

3.2.2 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the wall-fired boilers:

- The SNCR system is designed to provide a 50 percent NO_x reduction from a baseline NO_x rate of 0.50 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit on the study boiler are as follows (refer to Table 3-1):

- The boiler efficiency reduces from 88.39 to 87.96 percent. The boiler heat input increases from 3,600 to 3,618 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 193 kW.

- The urea consumption requirement for the SNCR system is 433 gal./hr.

- The water consumption requirement for the SNCR system is 5,570 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (30 to 1,300 MW) of wall-fired boilers. As shown in Figure 3-16, the capital costs range from approximately \$6.5 to \$52/kW. The levelized costs at a capacity factor of 65 percent range from 1.18 to 2.32 mils/kWh and \$980 to \$1,920/ton NO_x removed (Figures 3-17 and 3-18). The levelized costs at a capacity

factor of 27 percent range from 1.39 to 4.1 mils/kWh and $1,180 to $3,400/ton NO_x removed (Figures 3-19 and 3-20).

3.3 Cell-Burner Boiler Applications

Only the SCR technology was evaluated for NO_x control on this boiler type. The design data for the representative boilers of 300 and 600 MW sizes selected for this evaluation are shown in Figures B3-3 and B3-4 of Appendix A.

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 1.0 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Similar to the methodology used in Appendix A, the evaluations are based on two representative boilers.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

	300 MW	600 MW
Auxiliary power consumption, kW	716	1,431
Anhydrous ammonia consumption, lb/hr	843	1,641
Average catalyst replacement, ft^3/yr	4,556	8,773

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (200 to 1,300 MW) of cell-burner boilers. As shown in Figure 3-21, the capital costs range from approximately $38.5 to $69/kW. The levelized costs at a capacity factor of 65 percent range from 2.13 to 3.8 mils/kWh and $610 to $800/ton NO_x removed (Figures 3-22 and 3-23). The levelized costs at a capacity factor of 27 percent range from 4.6 to 6.8 mils/kWh and $1,305 to $1,780/ton NO_x removed (Figures 3-24 and 3-25).

3.4 Cyclone-Fired Boiler Applications

Only the SCR technology was evaluated for NO_x control on this boiler type. The design data for the representative boilers of 150 and 400 MW sizes selected for this evaluation are shown in Figures B4-3 and B4-4 of Appendix A.

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 1.17 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Similar to the methodology used in Appendix A, the evaluations are based on two representative boilers.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

	150 MW	400 MW
Auxiliary power consumption, kW	250	954
Anhydrous ammonia consumption, lb/hr	490	1,380
Average catalyst replacement, ft^3/yr	2,320	6,400

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (25 to 1,200 MW) of cyclone boilers. As shown in Figure 3-26, the capital costs range from approximately $44 to $120/kW. The levelized costs at a capacity factor of 65 percent range from 2.8 to 4.3 mils/kWh and $525 to $990/ton NO_x removed (Figures 3-27 and 3-28). The levelized costs at a capacity factor of 27 percent range from 5.9 to 9.8 mils/kWh and $1,080 to $2,270/ton NO_x removed (Figures 3-29 and 3-30).

3.5 Wet-Bottom Boiler Applications

Only the SCR technology was evaluated for NO_x control on this boiler type. The design data for the representative boilers of 100 and 259 MW sizes selected for this evaluation are shown in Figures B5-3 and B5-4 of Appendix A.

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 1.13 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Similar to the methodology used in Appendix A, the evaluations are based on two representative boilers.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

	100 MW	259 MW
Auxiliary power consumption, kW	240	620
Anhydrous ammonia consumption, lb/hr	320	840
Average catalyst replacement, ft^3/yr	1,570	4,080

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (25 to 800 MW) of wet-bottom boilers. As shown in Figure 3-31, the capital costs range from approximately $46 to $130/kW. The levelized costs at a capacity factor of 65 percent range from 2.65 to 4.65 mils/kWh and $560 to $1,100/ton NO_x removed (Figures 3-32 and 3-33). The levelized costs at a capacity factor of 27 percent range from 5.7 to 10.6 mils/kWh and $1,200 to $2,500/ton NO_x removed (Figures 3-34 and 3-35).

3.6 Vertically Fired, Dry-Bottom Boiler Applications

Only the SCR technology was evaluated for NO_x control on this boiler type. The design data for the representative boilers of 110 and 220 MW sizes selected for this evaluation are shown in Figures B6-3 and B6-4 of Appendix A.

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 1.08 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Similar to the methodology used in Appendix A, the evaluations are based on two representative boilers.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

	110 MW	220 MW
Auxiliary power consumption, kW	260	525
Anhydrous ammonia consumption, lb/hr	350	640
Average catalyst replacement, ft^3/yr	1,750	3,200

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (25 to 300 MW) of ver-

tically fired boilers. As shown in Figure 3-36, the capital costs range from approximately $57 to $151/kW. The levelized costs at a capacity factor of 65 percent range from 2.65 to 5.25 mils/kWh and $720 to $1,170/ton NO_x removed (Figures 3-37 and 3-38). The levelized costs at a capacity factor of 27 percent range from 5.85 to 12.0 mils/kWh and $1,590 to $2,650/ton NO_x removed (Figures 3-39 and 3-40).

TABLE 3-1

ORIGINAL DESIGN DATA
TANGENTIAL AND WALL-BURNER COAL-FIRED BOILERS

Parameter[1]	Tangential Boiler[2]	Wall-Fired Boiler[2]
Boiler size, MW	348	381
Boiler load, % MCR	100	100
Boiler type	Reheat	Reheat
Heat input, MMBtu/hr	3,210	3,600
Fuel consumption, ton/hr	127	142
Solid waste, ton/hr	9.82	10.98
Boiler efficiency	88.39	88.39
Fuel analysis (wt. %):		
Ash	7.7	7.7
Moisture	8.4	8.4
Sulfur	0.8	0.8
HHV, Btu/lb	12,696	12,696

NOTES

1. Only data pertinent to the NO_x control technologies are shown.

2. The same coal is fired in both boilers. It is assumed that efficiency is the same for both boiler types. In practice, there may be a small difference in the efficiencies; however, the difference would be insignificant as long as the operating parameters, such as excess air levels, are the same.

4.0 NATURAL GAS-FIRED PLANT ASSUMPTIONS AND RESULTS

Both the tangential and wall-fired boilers firing natural gas have been considered in this evaluation. The NO_x control technologies evaluated for these boiler types include SCR, gas reburning, and SNCR. The design data for the representative boilers selected for this evaluation are shown in Table 4-1. It is to be noted that the same design data apply to both the tangential and wall-fired boilers.

The tangential boiler is a balanced draft, forced circulation, reheat, single furnace boiler. It has four windboxes located along the four corners of the furnace. There are a total of 16 burners, four per corner. The boiler serves a 350 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans and two 50-percent-capacity induced draft fans.

The wall-fired boiler is a balanced draft, natural circulation, reheat, single furnace boiler. It is a front wall-fired boiler with 20 burners arranged four high and five wide. The boiler serves a 350 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans and two 50-percent-capacity induced draft fans.

4.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the tangential and wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.25 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Since the flue gas flow conditions at the economizer outlet are the same for both the tangential and wall-fired boilers, the SCR system design would be extremely similar for these boilers, which permits a joint presentation of the cost data for these boilers.

- Similar to the coal-fired tangential boiler case, the evaluation is based on one representative boiler for each boiler type.

- A catalyst operating life of 5 years is assumed.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

Auxiliary power consumption	420 kW
Anhydrous ammonia consumption	130 lb/hr
Average catalyst replacement	425 ft^3/yr

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 4-1, the capital costs range from approximately \$14 to \$54/kW. The levelized costs at a capacity factor of 65 percent range from 0.55 to 1.5 mils/kWh and \$1,350 to \$3,750/ton NO_x removed (Figures 4-2 and 4-3). The levelized costs at a capacity factor of 27 percent range from 1.15 to 3.44 mils/kWh and \$2,900 to \$8,600/ton NO_x removed (Figures 4-4 and 4-5).

4.2 Gas Reburning Evaluation

The following major criteria and assumptions have been followed in evaluating the gas reburning technology for the gas-fired boilers:

- The gas reburn system is designed to reduce the baseline NO_x of 0.25 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- It is assumed that natural gas supply is available at the plant fence for both boilers.

- The reburn system design is based on a 25 percent heat input for the reburn injectors. Natural gas is injected into the furnace along with gas recirculation (system designed for a 10 percent recirculation rate). It is assumed that existing gas recirculation fans will be used for this purpose. The overfire air system is designed for 20 percent of the full-load combustion air requirement for the boiler.

- It is assumed that sufficient space is available in the boilers to add the reburn injectors and overfire air ports. It is also assumed that the available space allows for an adequate residence time for completing the combustion process for the reburn fuel. Lack of an adequate residence time may reduce the effectiveness of the gas reburn system or it may adversely affect the feasibility of installing such a system.

- In some cases, capital cost of the reburn technology application may be lower for a tangential boiler than for a wall-fired boiler. Because of the corner firing arrangement for the tangential boiler, a potential may exist for effectively utilizing a smaller number of reburn injectors. However, any cost difference is not expected to be significant. Therefore, for conservatism, the same capital costs developed for the wall-fired boiler have been used for the tangential boiler.

- Other general gas reburn system design details, assumptions, and impacts on the existing equipment outlined in Appendix A (Section 4.3 of Appendix B) also apply to this case.

Reburn technology has a minimal impact on the performance of a gas-fired boiler. This application involves withdrawal of a portion of the boiler fuel from the main combustion zone and injection of this fuel above the top-most burners. Overfire air is injected further up in the furnace to complete combustion of the reburn fuel. As long as the conditions permit proper combustion of the reburn fuel, the boiler performance would not be affected. Operation of the reburn system does result in an increased auxiliary power consumption (associated with the operation of the gas recirculation fan). In the case of the study boilers, this increase is estimated at 176 MW.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 4-6, the capital costs range from approximately $10 to $37/kW. The levelized costs at a capacity factor of 65 percent range from 0.28 to 0.95 mils/kWh and $700 to $2,400/ton NO_X removed (Figures 4-7 and 4-8). The levelized costs at a capacity factor of 27 percent range from 1.32 to 3.78 mils/kWh and $1,330 to $3,800/ton NO_X removed (Figures 4-9 and 4-10).

4.3 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the gas-fired boilers:

- The SNCR system is designed to reduce the baseline NO_X of 0.25 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- A reagent ratio of 1.5 commensurate with the NO_X reduction requirement is used.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit on the study boilers are as follows (refer to Table 4-1):

- The boiler efficiency reduces from 85.65 to 85.48 percent. The boiler heat input increases from 2,980 to 2,986 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 80 kW.

- The urea consumption requirement for the SNCR system is 155 gal./hr.

- The water consumption requirement for the SNCR system is 1,980 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 4-11, the capital costs range from approximately $3.2 to $28/kW. The levelized costs at a capacity factor of 65 percent range from 0.5 to 1.1 mils/kWh and $1,220 to $2,800/ton NO_X removed (Figures 4-12 and 4-13). The levelized costs at a capacity factor of 27 percent range from 0.6 to 2.1 mils/kWh and $1,520 to $5,200/ton NO_X removed (Figures 4-14 and 4-15).

TABLE 4-1

ORIGINAL DESIGN DATA
TANGENTIAL AND WALL-BURNER TYPE
GAS- AND OIL-FIRED BOILERS

Parameter[1]	Gas-Fired Boilers[2]	Oil-Fired Boilers[2]
Boiler size, MW	350	350
Boiler load, % MCR	100	100
Boiler type	Reheat	Reheat
Heat input, MMBtu/hr	2,980	2,895
Fuel consumption, ton/hr	64.1	79.5
Solid waste, lb/hr	0	303
Boiler efficiency	85.65	88.15
Fuel analysis (wt. %):	Natural Gas	No. 6 Oil
Ash		0.1
Moisture		0.1
Sulfur		1.0
HHV, Btu/lb		18,200
CH_4	85.45	
C_3H_8	2.45	
C_2H_6	6.61	
HHV, Btu/ft^3	1,075	

NOTES

1. Only data pertinent to the NO_x control technologies are shown.

2. For each fuel, the same design data apply to both the tangential and wall-fired boilers. It is assumed that efficiency is the same for both boiler types. In practice, there may be a small difference in the efficiencies; however, the difference would be insignificant as long as the operating parameters, such as excess air levels, are the same.

5.0 OIL-FIRED PLANT ASSUMPTIONS AND RESULTS

Both the tangential and wall-fired boilers firing No. 6 oil have been considered in this evaluation. The NO_x control technologies evaluated for these boiler types include SCR, gas reburning, and SNCR. The design data for the representative boilers selected for this evaluation are shown in Table 4-1. It is to be noted that the same design data apply to both the tangential and wall-fired boilers.

The tangential boiler is a balanced draft, forced circulation, reheat, single furnace boiler. It has four windboxes located along the four corners of the furnace. There are a total of 16 burners, four per corner. The boiler serves a 350 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

The wall-fired boiler is a balanced draft, natural circulation, reheat, single furnace boiler. It is a front wall-fired boiler with 20 burners arranged four high and five wide. The boiler serves a 350 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

5.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the tangential and wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.30 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Since the flue gas flow conditions at the economizer outlet are the same for both the tangential and wall-fired boilers, the SCR system design would be extremely similar for these boilers, which permits a joint presentation of the cost data for these boiler.

- Similar to the coal-fired tangential boiler case, the evaluation is based on one representative boiler for each boiler type.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boilers are as follows:

Auxiliary power consumption	500 kW
Anhydrous ammonia consumption	170 lb/hr
Average catalyst replacement	1,370 ft^3/yr

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-1, the capital costs range from approximately $21 to $77/kW. The levelized costs at a capacity factor of 65 percent range from 0.87 to 2.27 mils/kWh and $1,500 to $3,800/ton NO_x removed (Figures 5-2 and 5-3). The levelized costs at a capacity factor of 27 percent range from 1.95 to 5.3 mils/kWh and $3,200 to $8,800/ton NO_x removed (Figures 5-4 and 5-5).

5.2 Gas Reburning Evaluation

The following major criteria and assumptions have been followed in evaluating the gas reburning technology for the oil-fired boilers:

- The gas reburn system is designed to reduce the baseline NO_x of 0.3 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Other criteria and assumptions outlined in Section 4.2 also apply to this case.

The performance impacts of the reburn technology on the oil-fired boilers are as follows:

- The boiler performance changes, because with the reburn system 20 percent of the heat input is by natural gas and 80 percent is by oil. The boiler efficiency reduces from 88.15 to 87.38 percent. The levelized cost estimates must take into account the cost increases incurred in firing natural gas rather than No. 6 oil.

- Firing of natural gas reduces the amount of ash generation by 58 lb/hr and SO_2 emission rate by 620 lb/hr. Both of these reductions benefit the operating costs.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-6, the capital costs range from approximately $12 to $44/kW. The levelized costs at a capacity factor of 65 percent range from 0.8 to 1.6 mils/kWh and $1,350 to $2,650/ton NO_x removed (Figures 5-7 and 5-8). The levelized costs at a capacity factor of 27 percent range from 1.2 to 3.1 mils/kWh and $2,000 to $5,200/ton NO_x removed (Figures 5-9 and 5-10).

5.3 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the oil-fired boilers:

- The SNCR system is designed to reduce the baseline NO_x of 0.3 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit to the study boilers are as follows (refer to Table 4-1):

- The boiler efficiency reduces from 88.15 to 87.88 percent. The boiler heat input increases from 2,895 to 2,904 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 115 kW.

- The urea consumption requirement for the SNCR system is 210 gal./hr.

- The water consumption requirement for the SNCR system is 2,690 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-11, the capital costs range from approximately \$4.0 to \$32/kW. The levelized costs at a capacity factor of 65 percent range from 0.65 to 1.35 mils/kWh and \$1,100 to \$2,300/ton NO_x removed (Figures 5-12 and 5-13). The levelized costs at a capacity factor of 27 percent range from 0.8 to 2.46 mils/kWh and \$1,350 to \$4,100/ton NO_x removed (Figures 5-14 and 5-15).
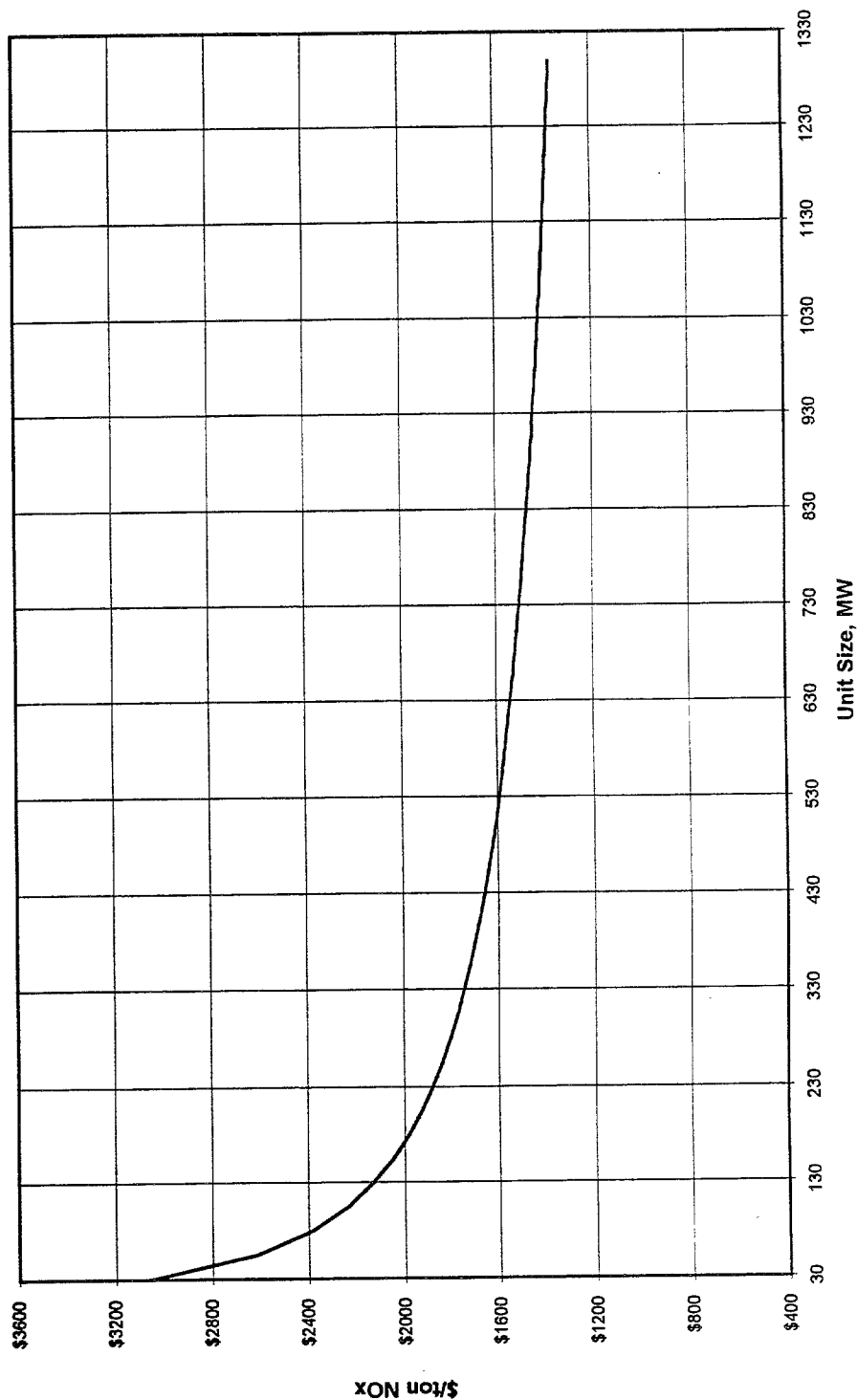
Figure 3-1
Coal-Fired, Tangential-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW
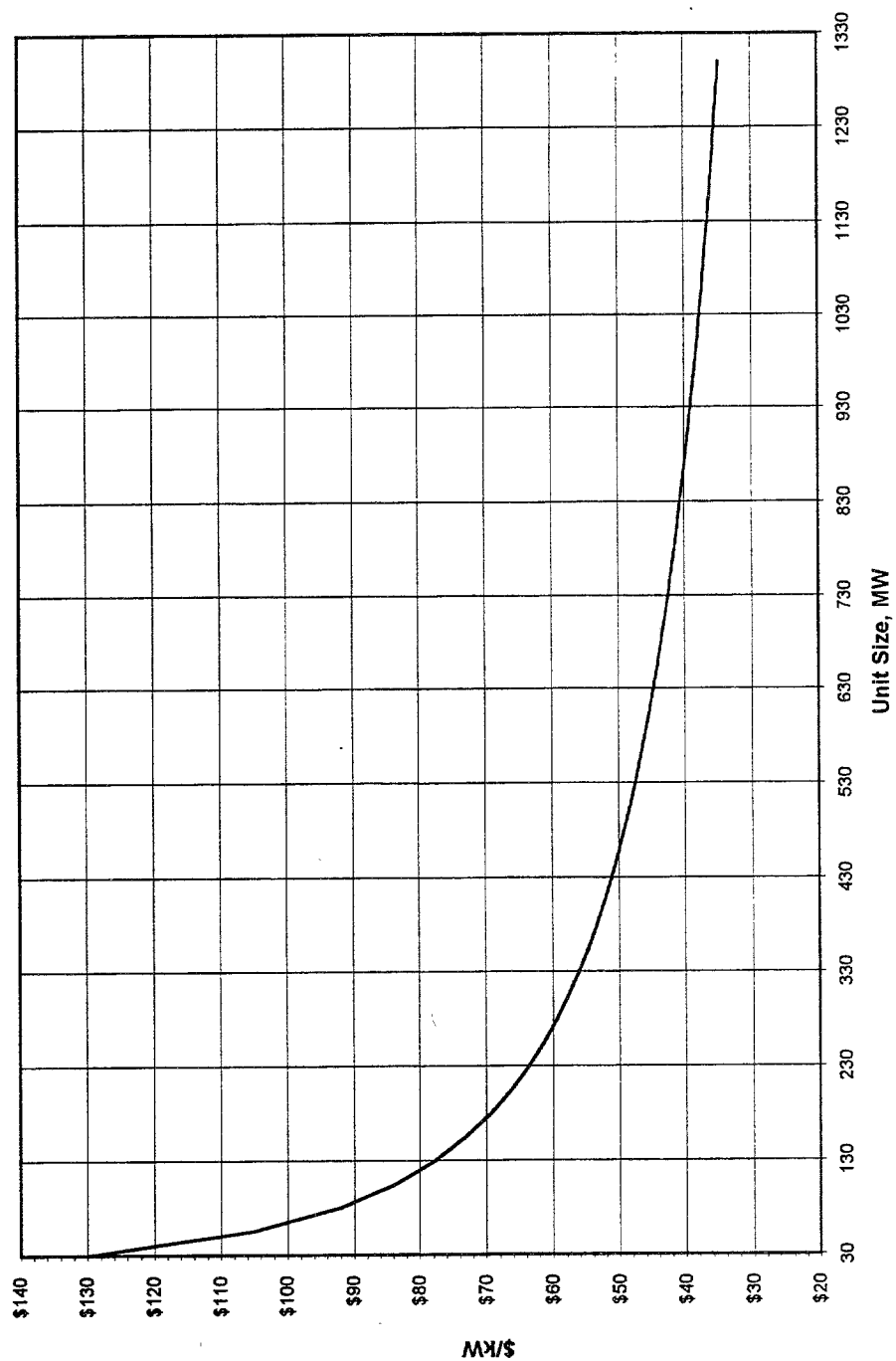
Figure 3-2
Coal-Fired, Tangential-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 85% Capacity Factor Case
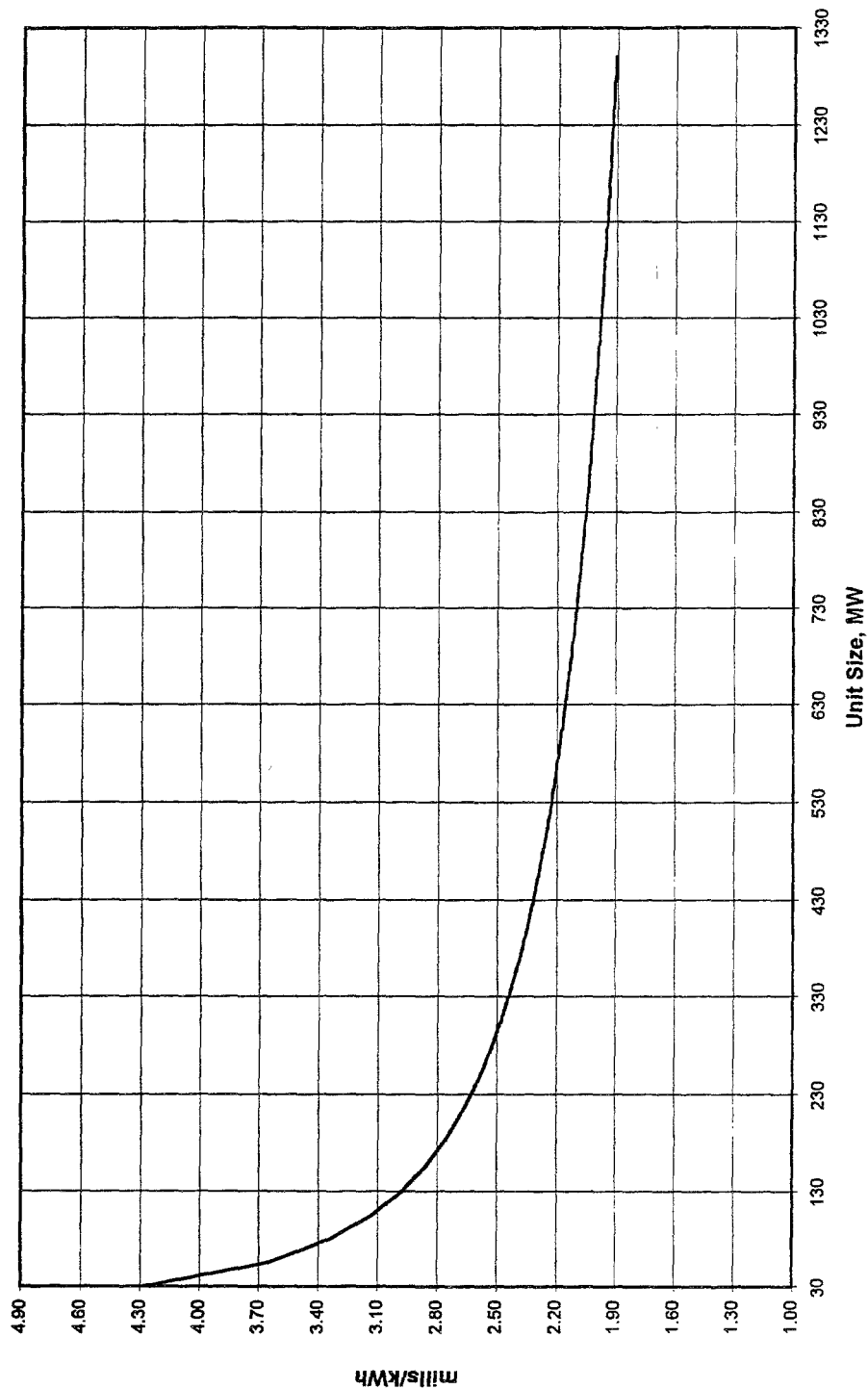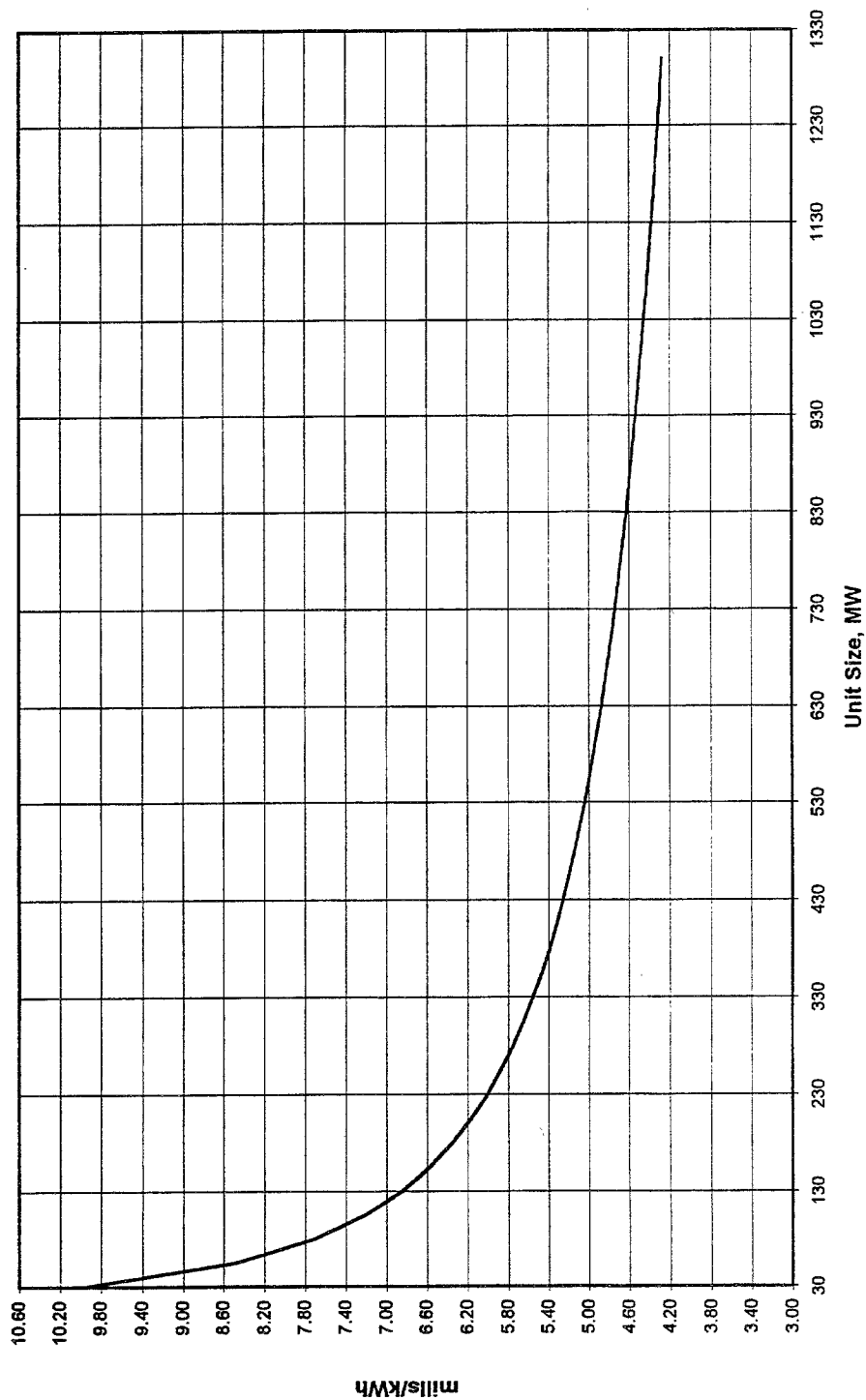
Figure 3-3
Coal-Fired, Tangential-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case

Figure 3-4
Coal-Fired, Tangential-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
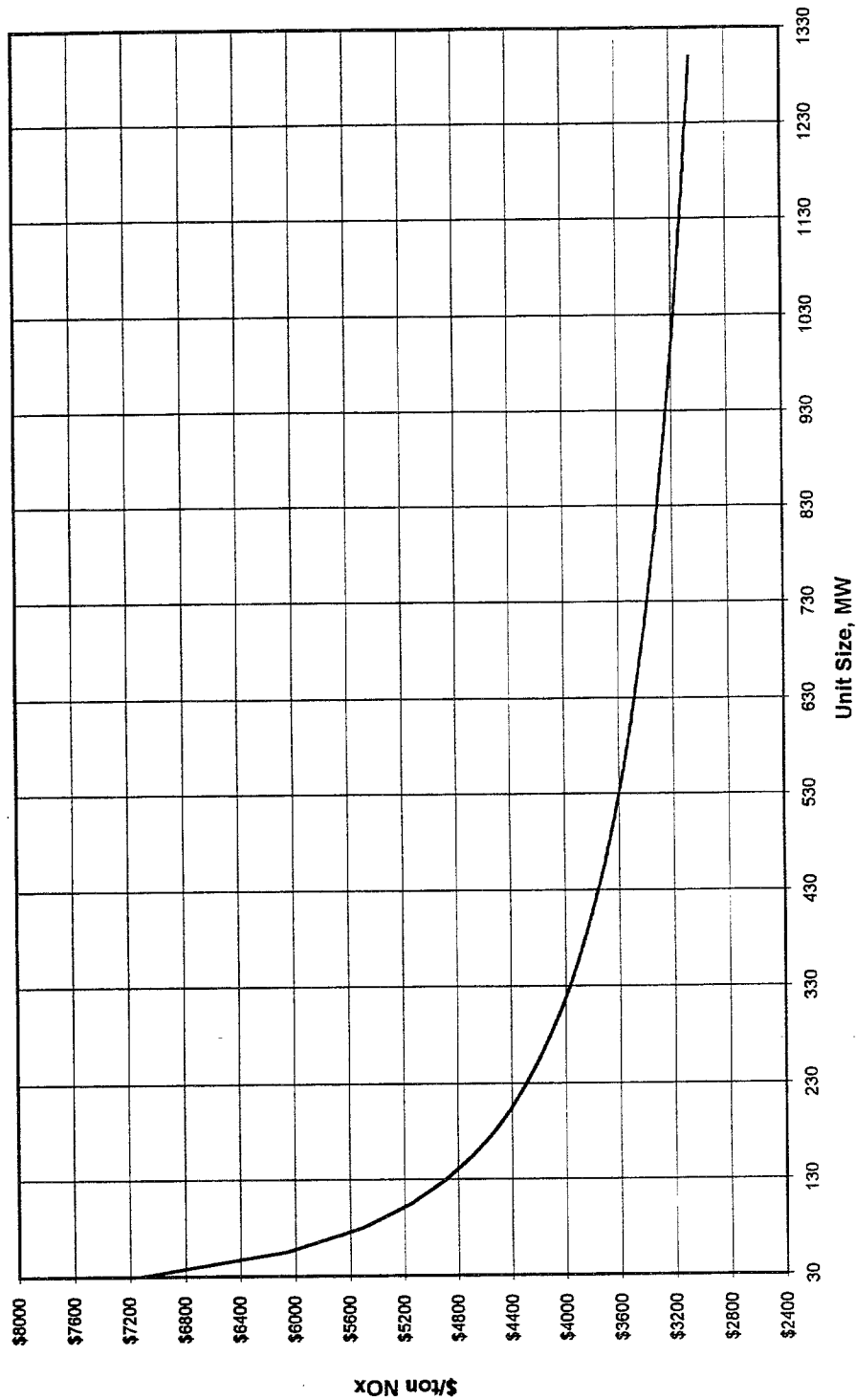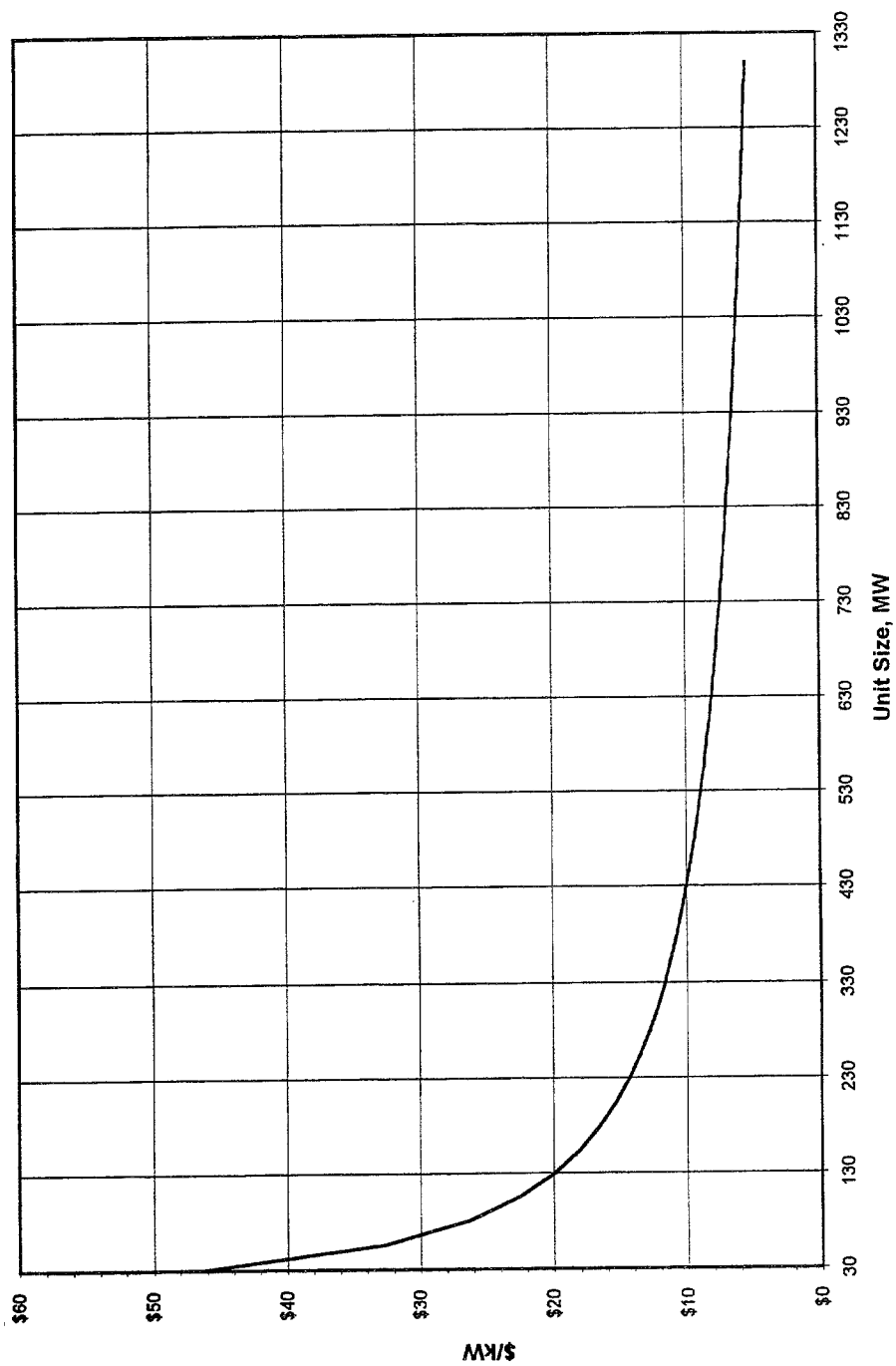**Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case**
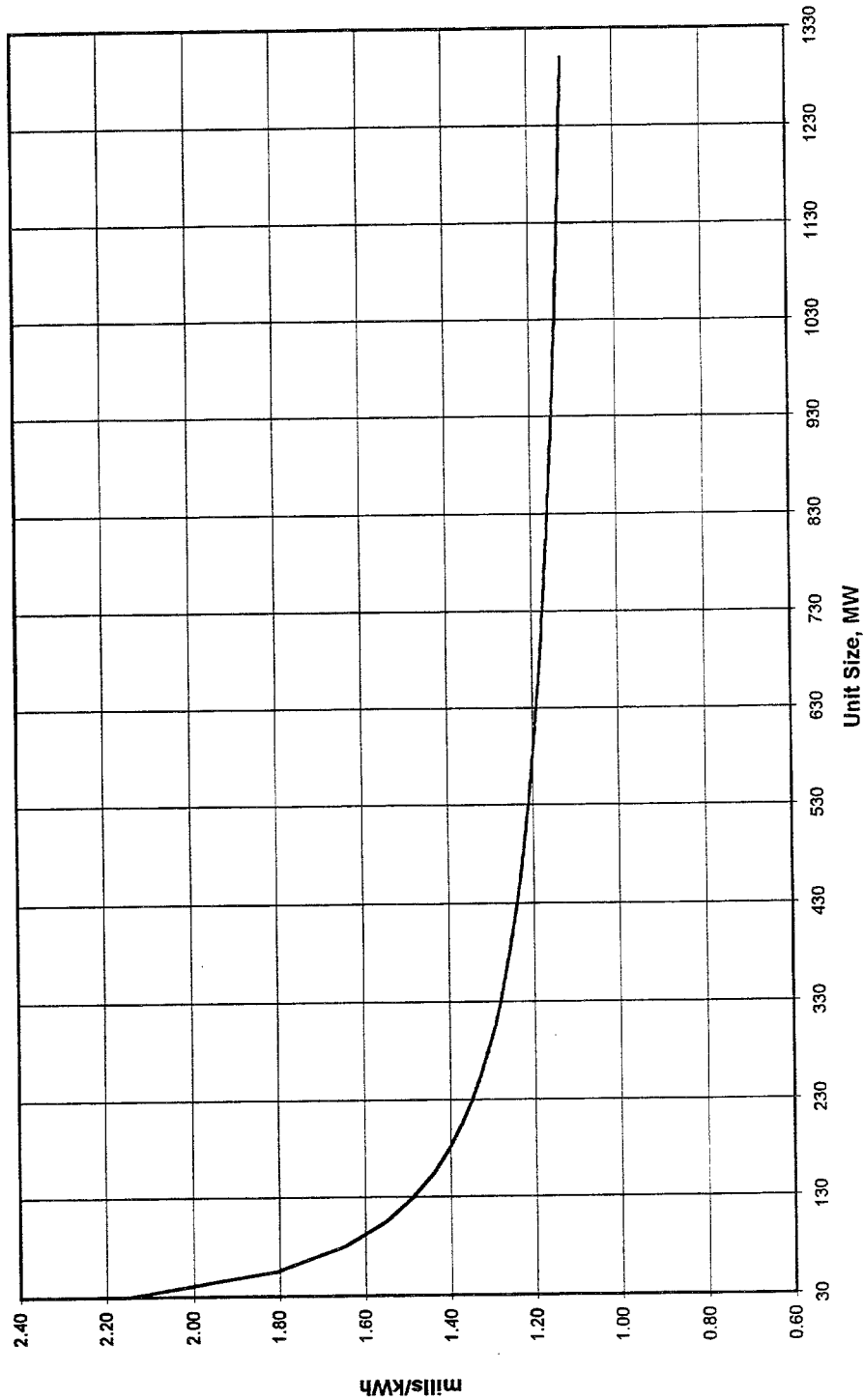
Figure 3-5
Coal-Fired, Tangential-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
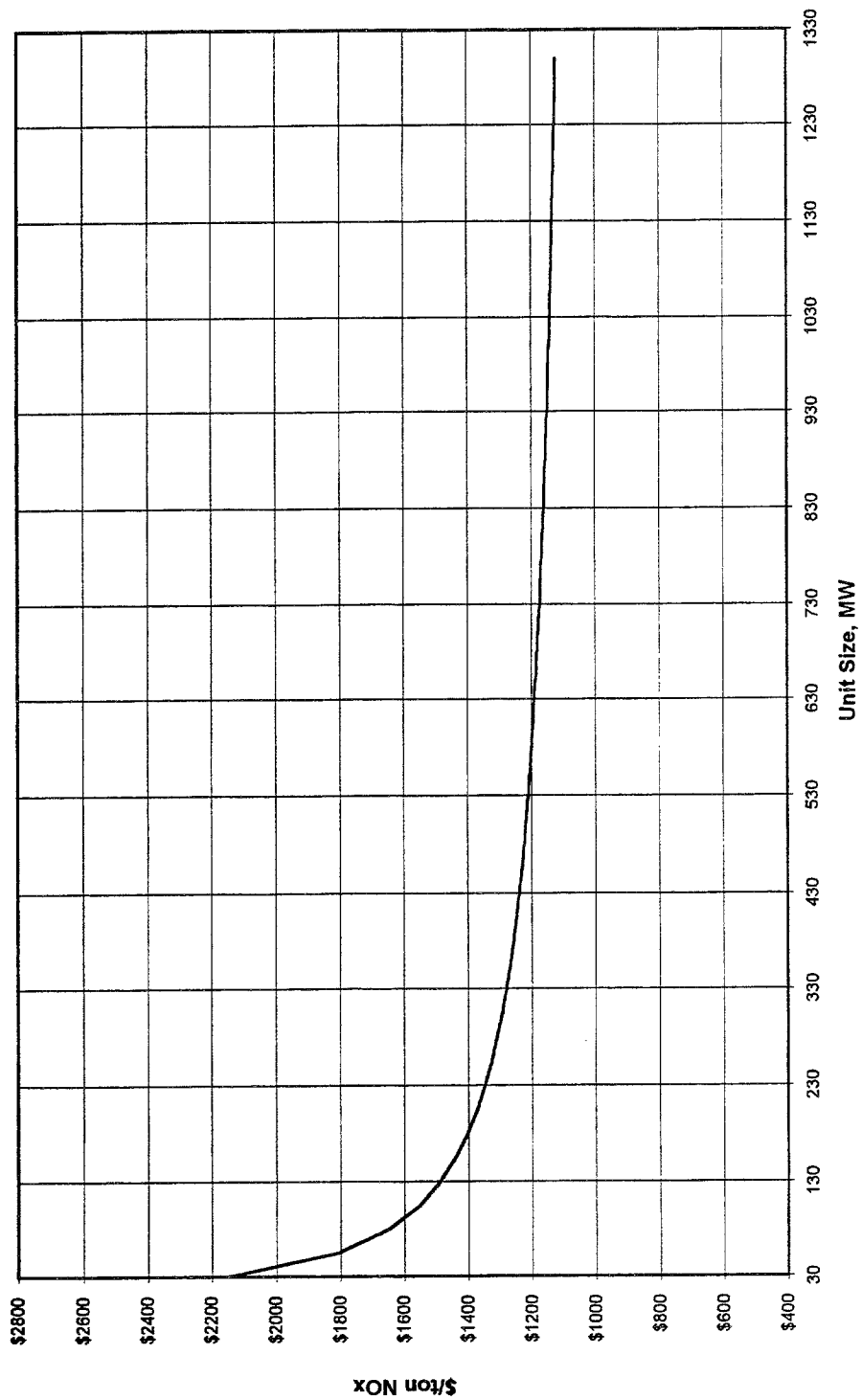**Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case**

Figure 3-6
Coal-Fired, Tangential Boiler, SNCR Retrofit
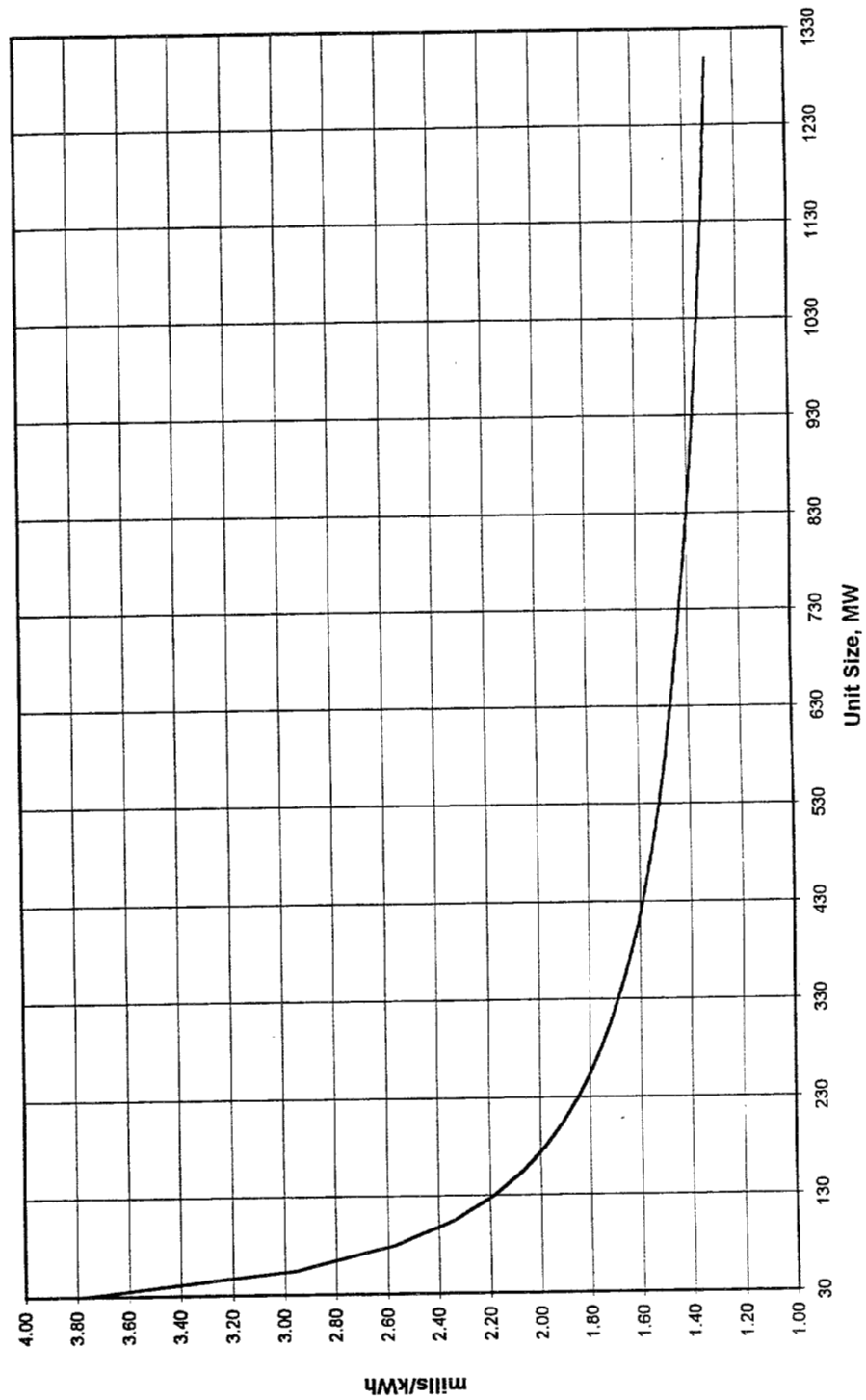Base Capital Costs v. MW

Figure 3-7
Coal-Fired, Tangential Boiler, SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case

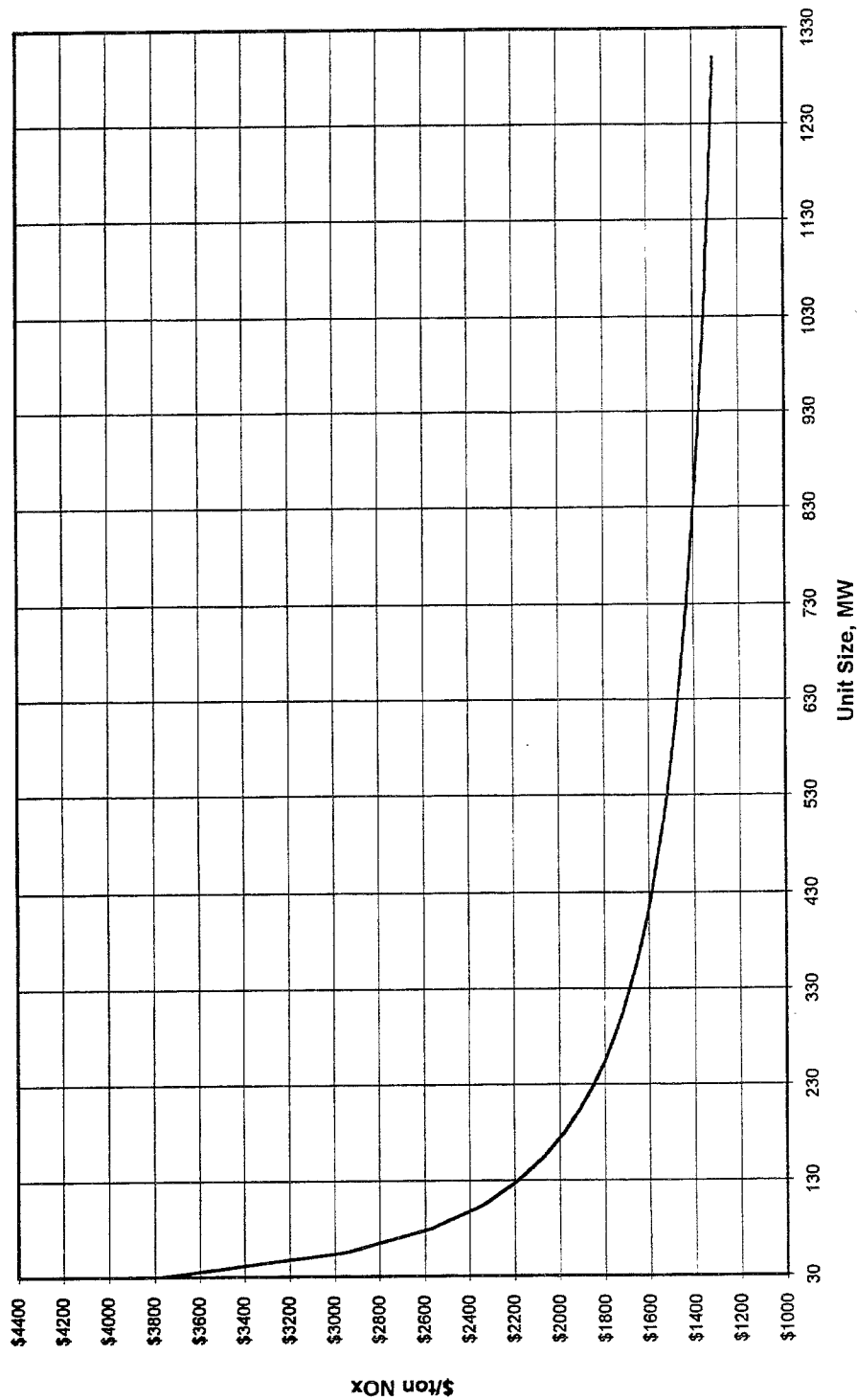**Figure 3-8**
Coal-Fired, Tangential Boiler, SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 85% Capacity Factor Case

Figure 3-9
Coal-Fired, Tangential Boiler, SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case

Figure 3-10
Coal-Fired, Tangential Boiler, SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW -27% Capacity Factor Case

Figure 3-11
Coal-Fired, Wall-Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW

Figure 3-12
Coal-Fired, Wall-Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case

Figure 3-13
Coal-Fired, Wall-Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
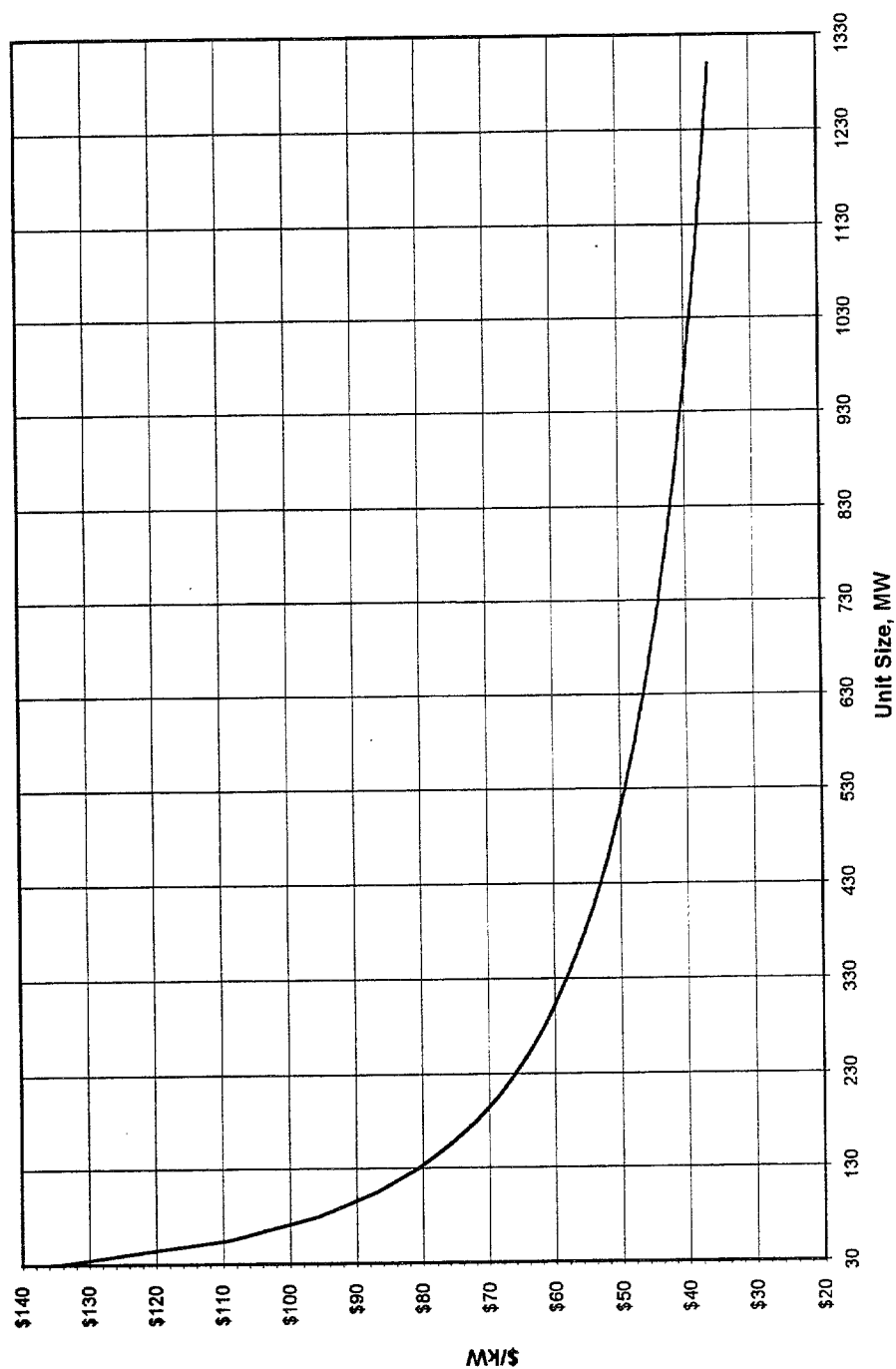Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case

Figure 3-14
Coal-Fired, Wall-Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case

Figure 3-15
Coal-Fired, Wall-Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case

Figure 3-16
Coal-Fired, Wall-Burner Boiler, SNCR Retrofit
Base Capital Costs v. MW

Figure 3-17
Coal-Fired, Wall-Burner Boiler, SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case

Figure 3-18
Coal-Fired, Wall-Burner Boiler, SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case

Figure 3-19
Coal-Fired, Wall-Burner Boiler, SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
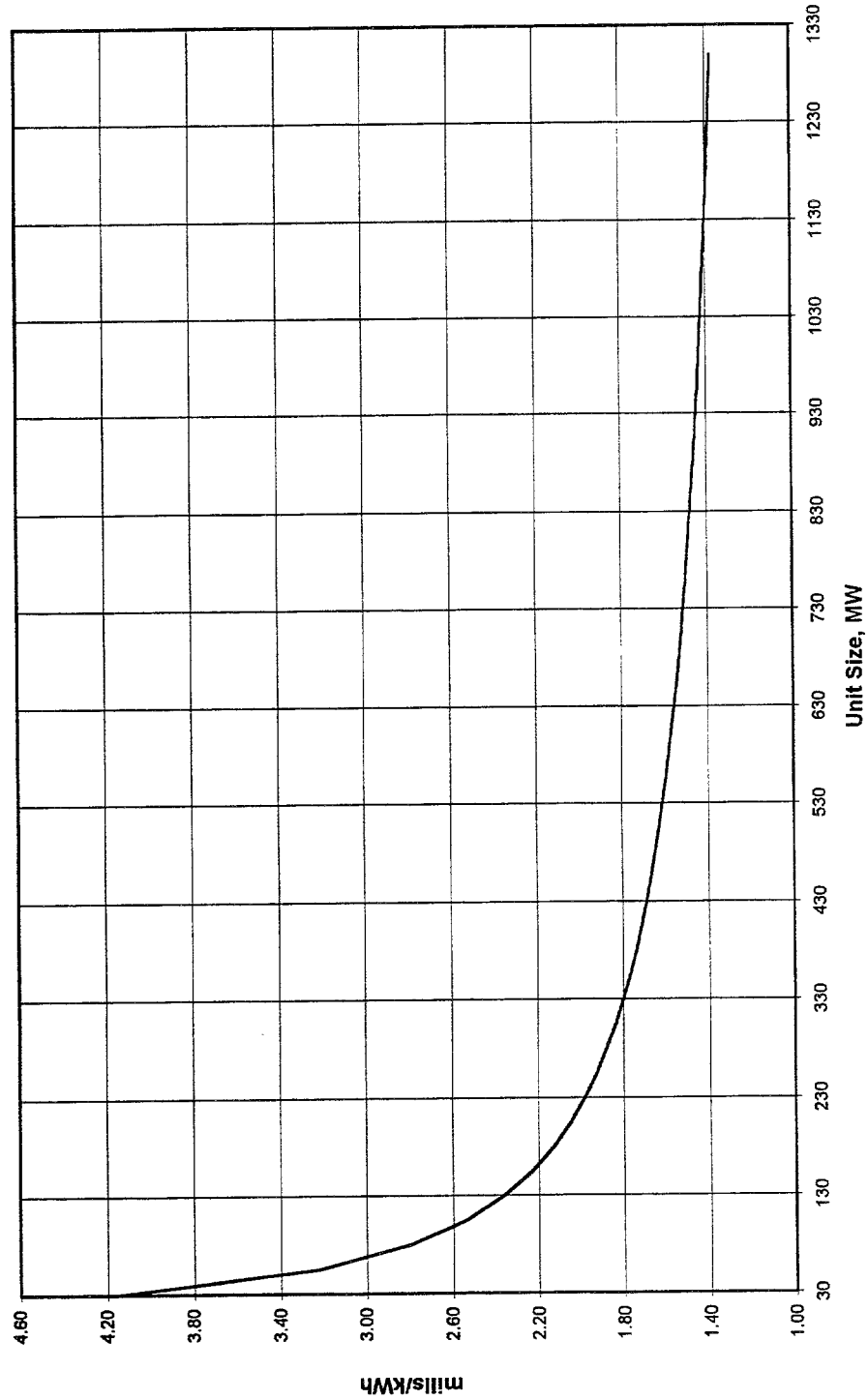
Figure 3-20
Coal-Fired, Wall-Burner Boiler, SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
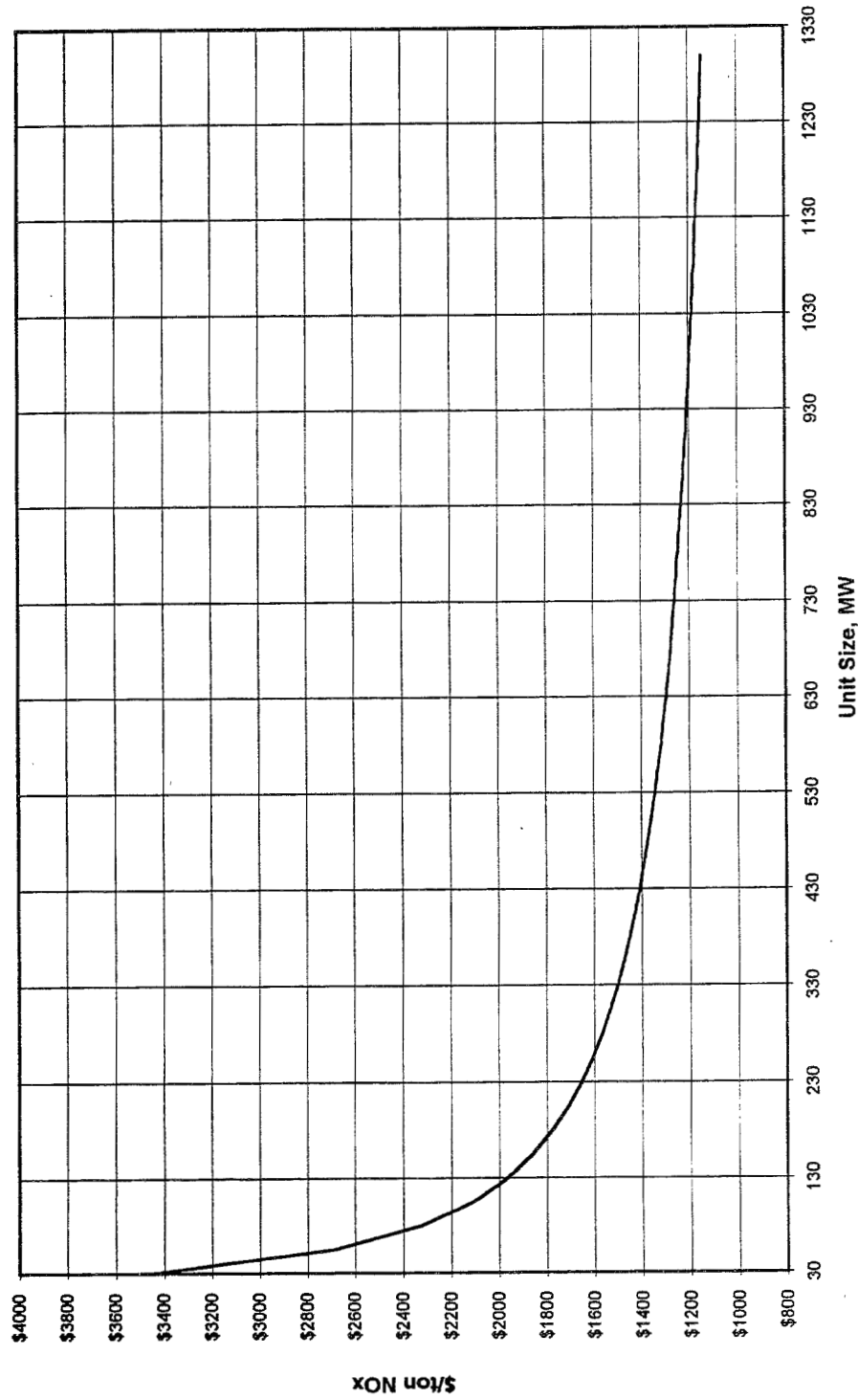
Figure 3-21
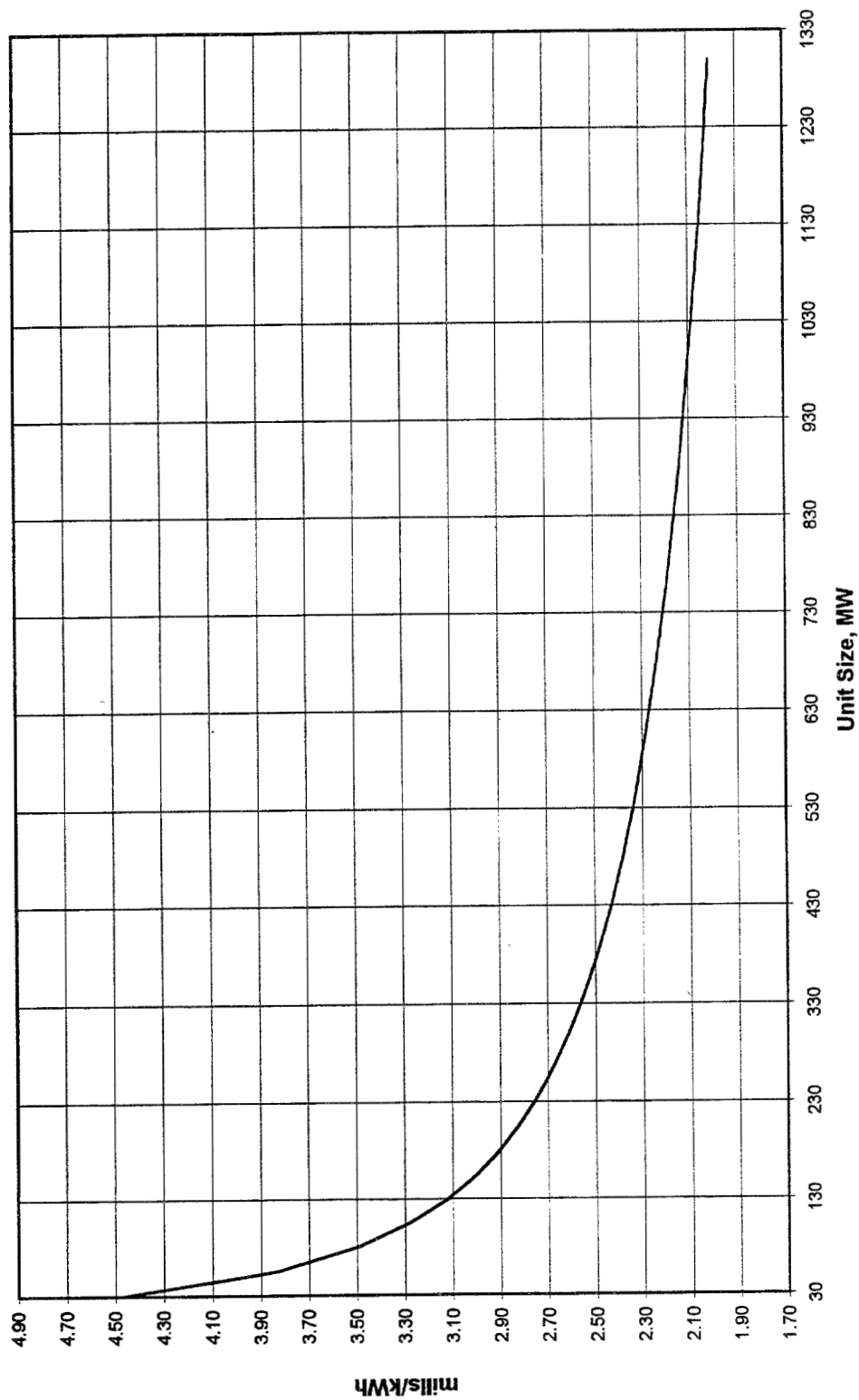Coal-Fired, Cell Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW

Unit Size, MW
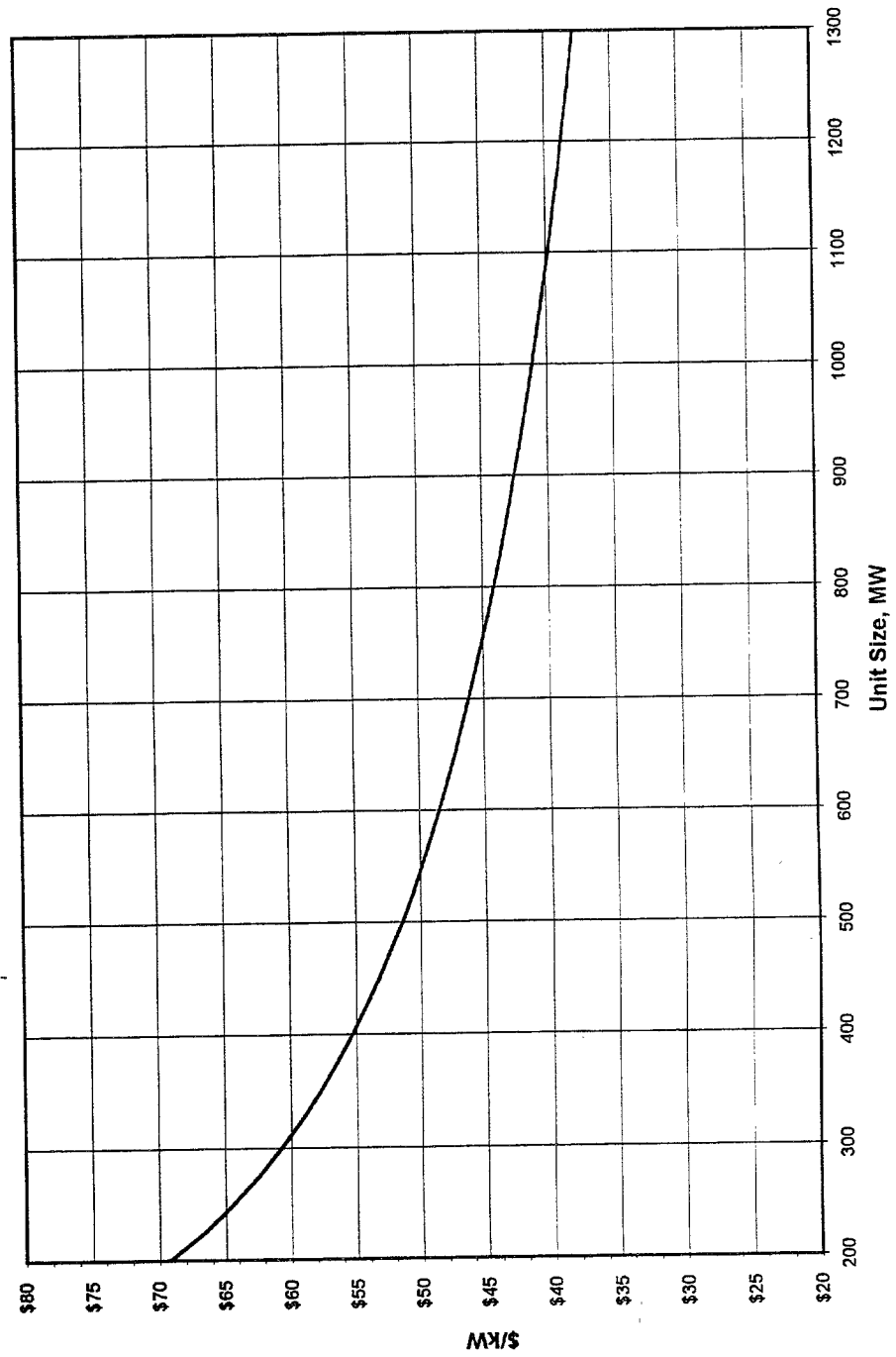
Figure 3-22
Coal-Fired, Cell Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
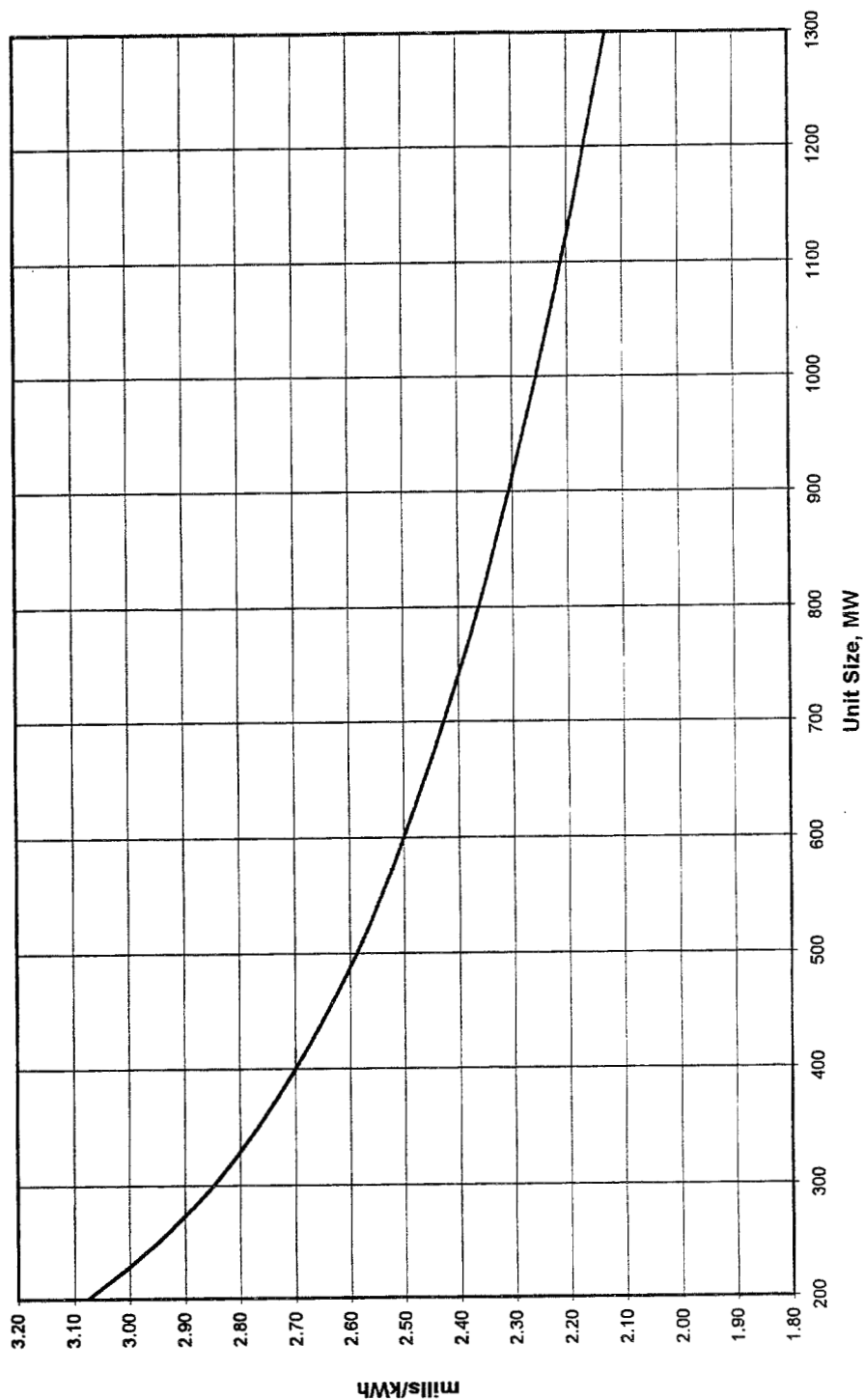
Figure 3-23
Coal-Fired, Cell Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
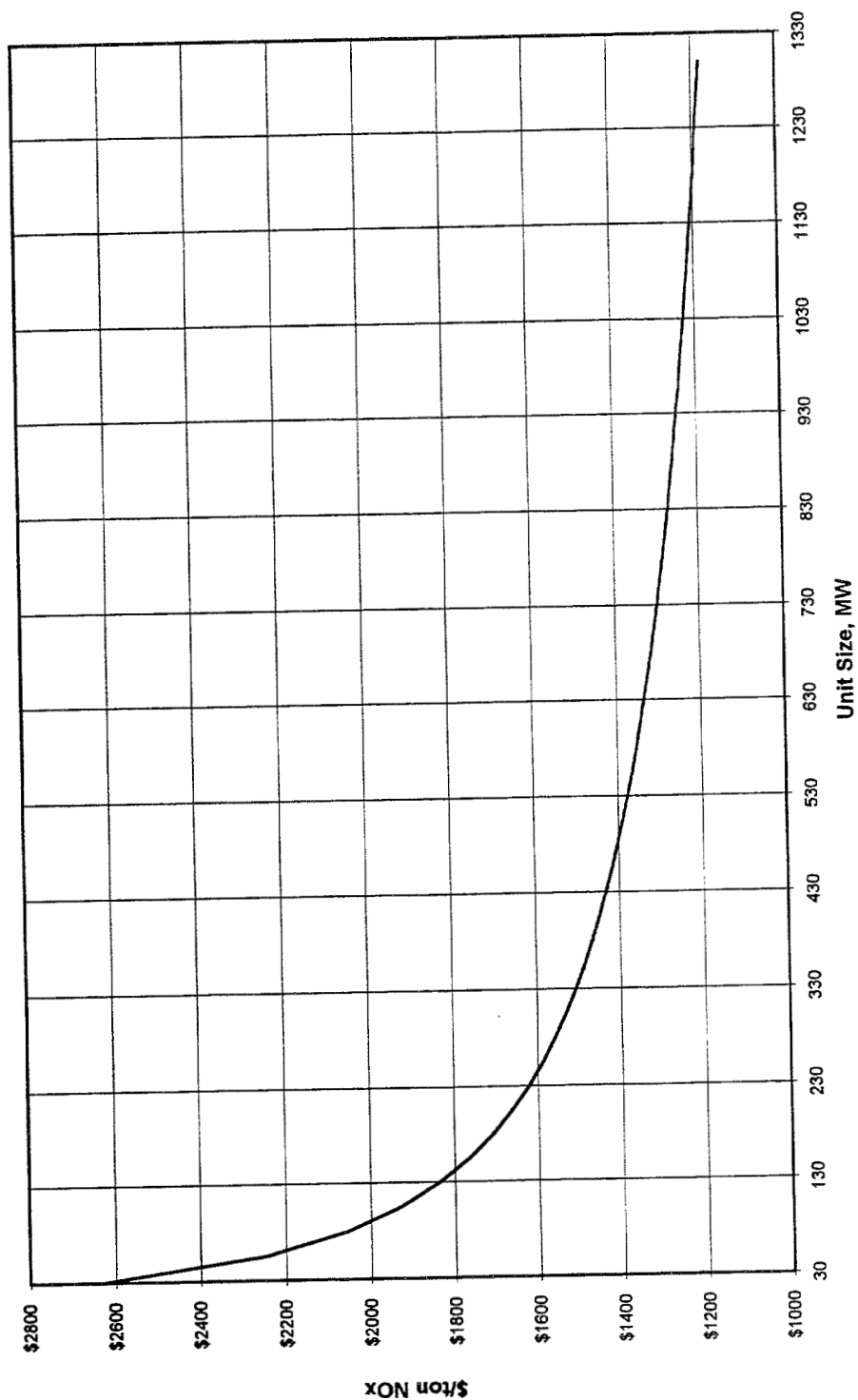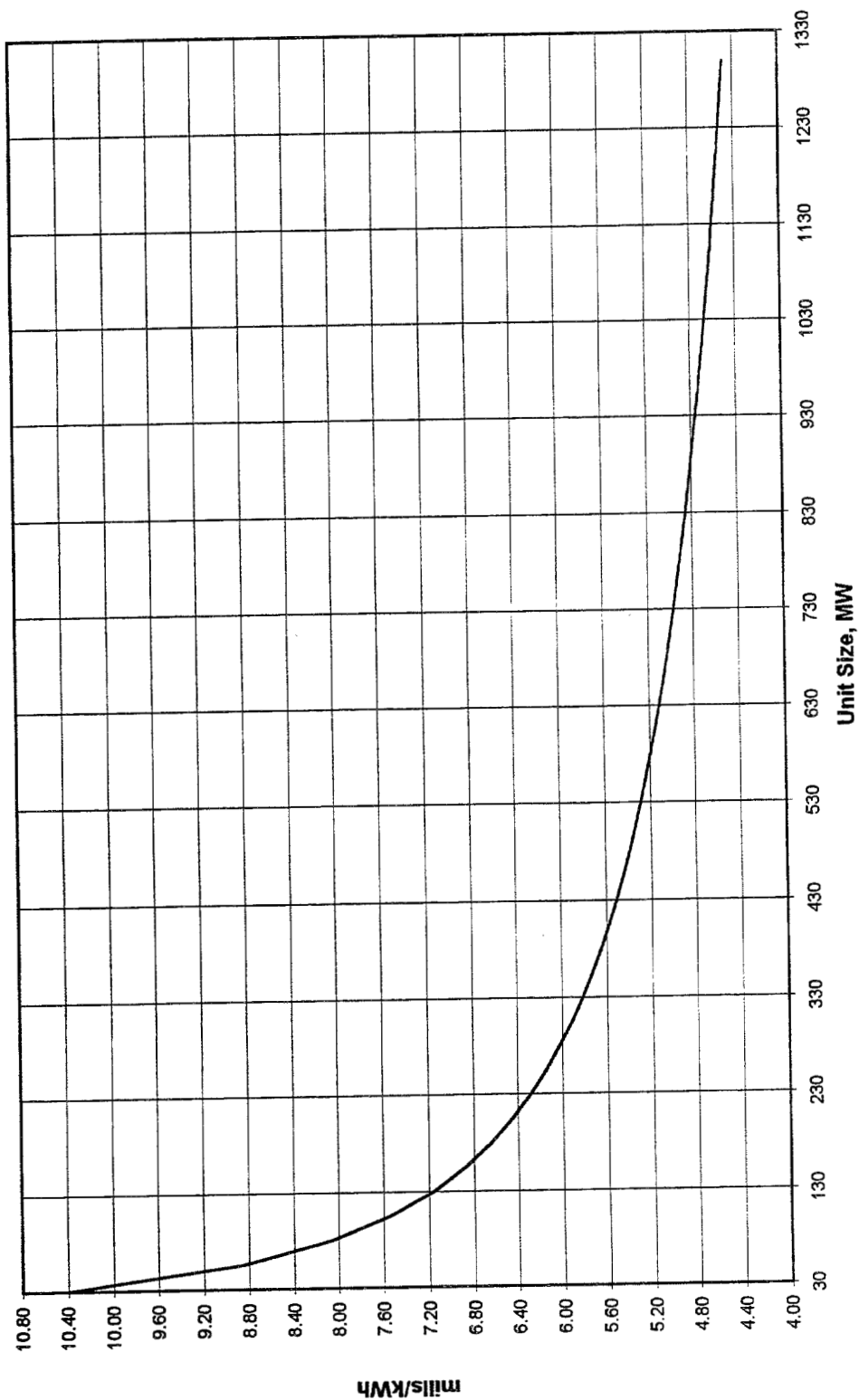Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
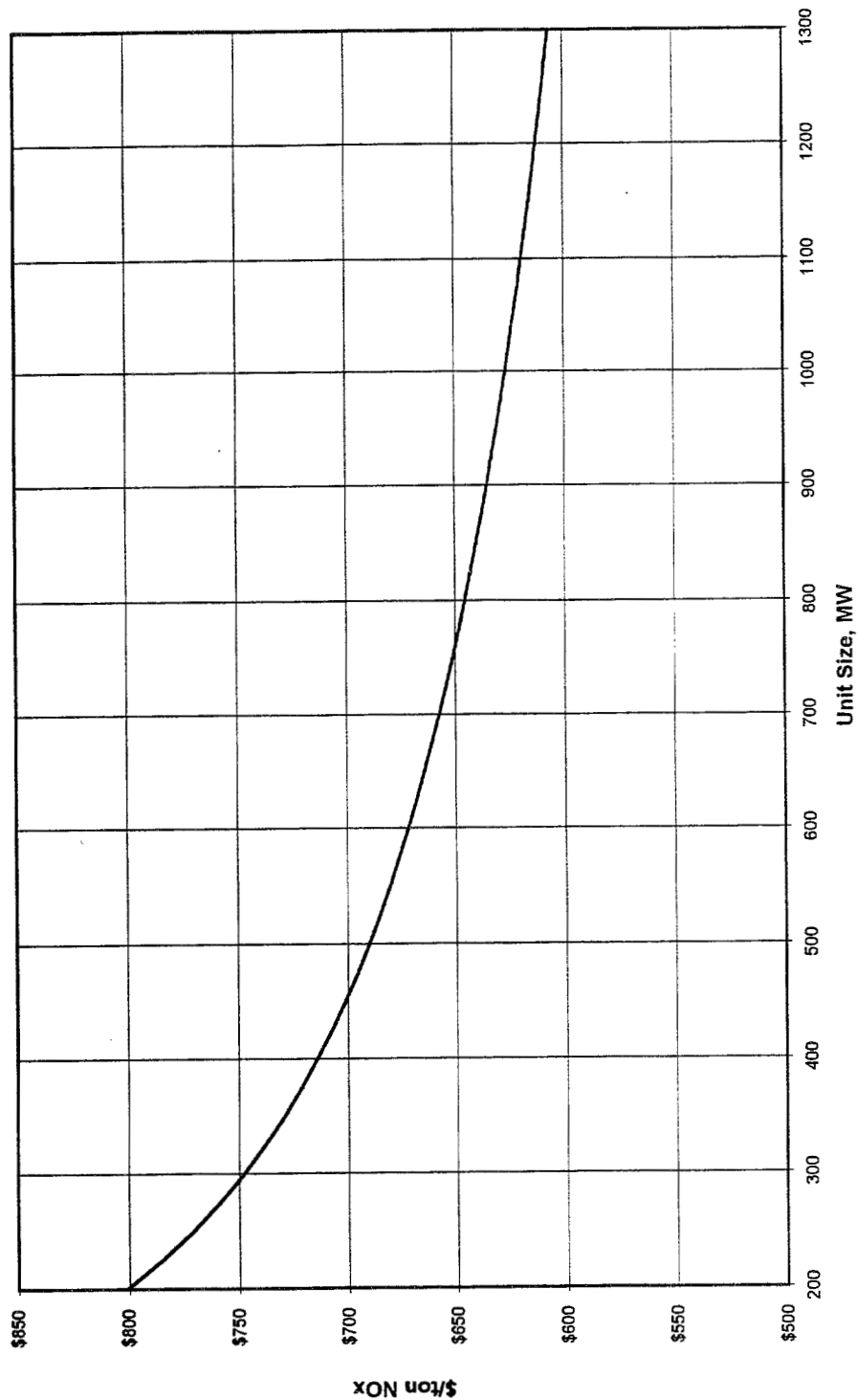
Figure 3-24
Coal-Fired, Cell Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
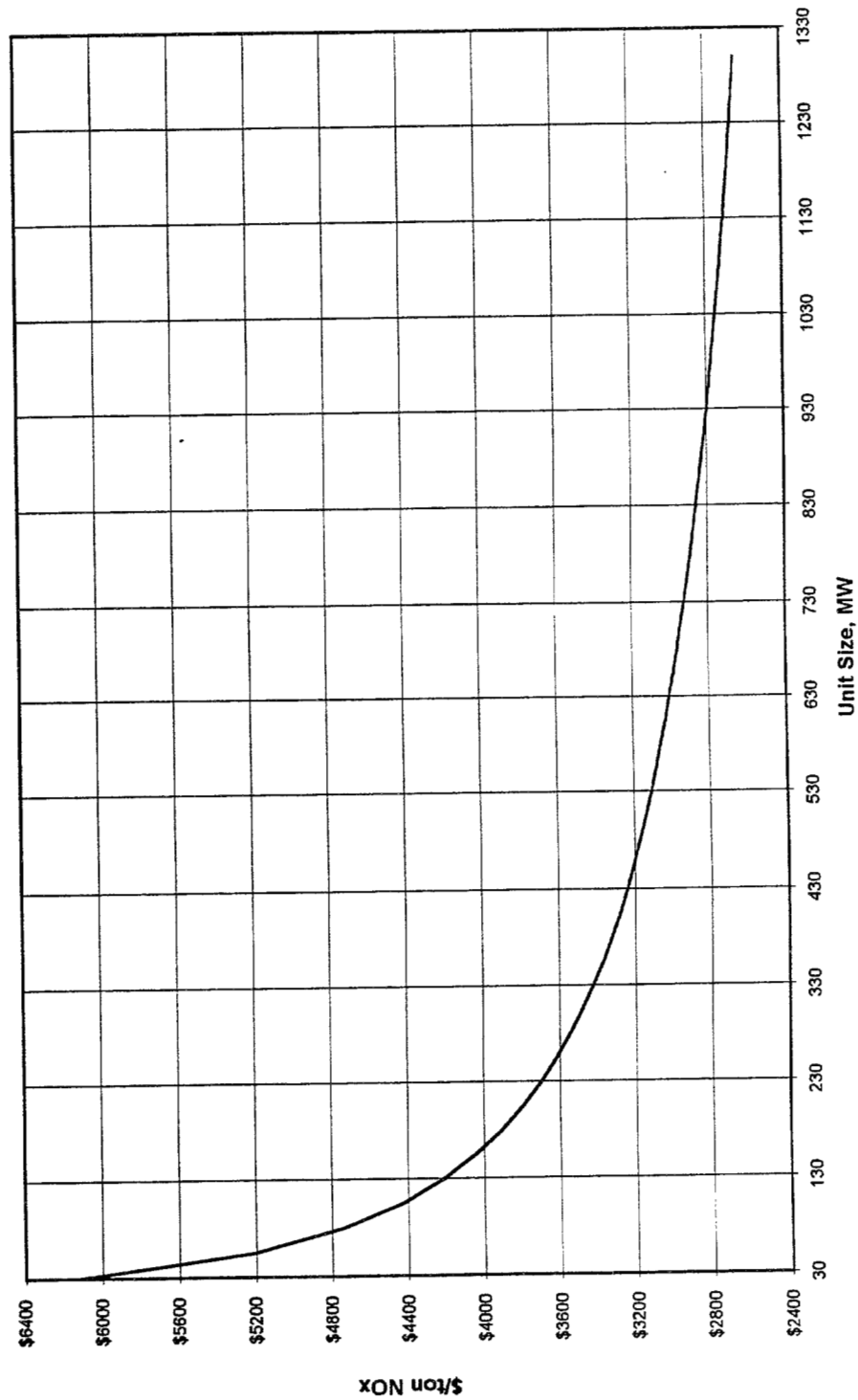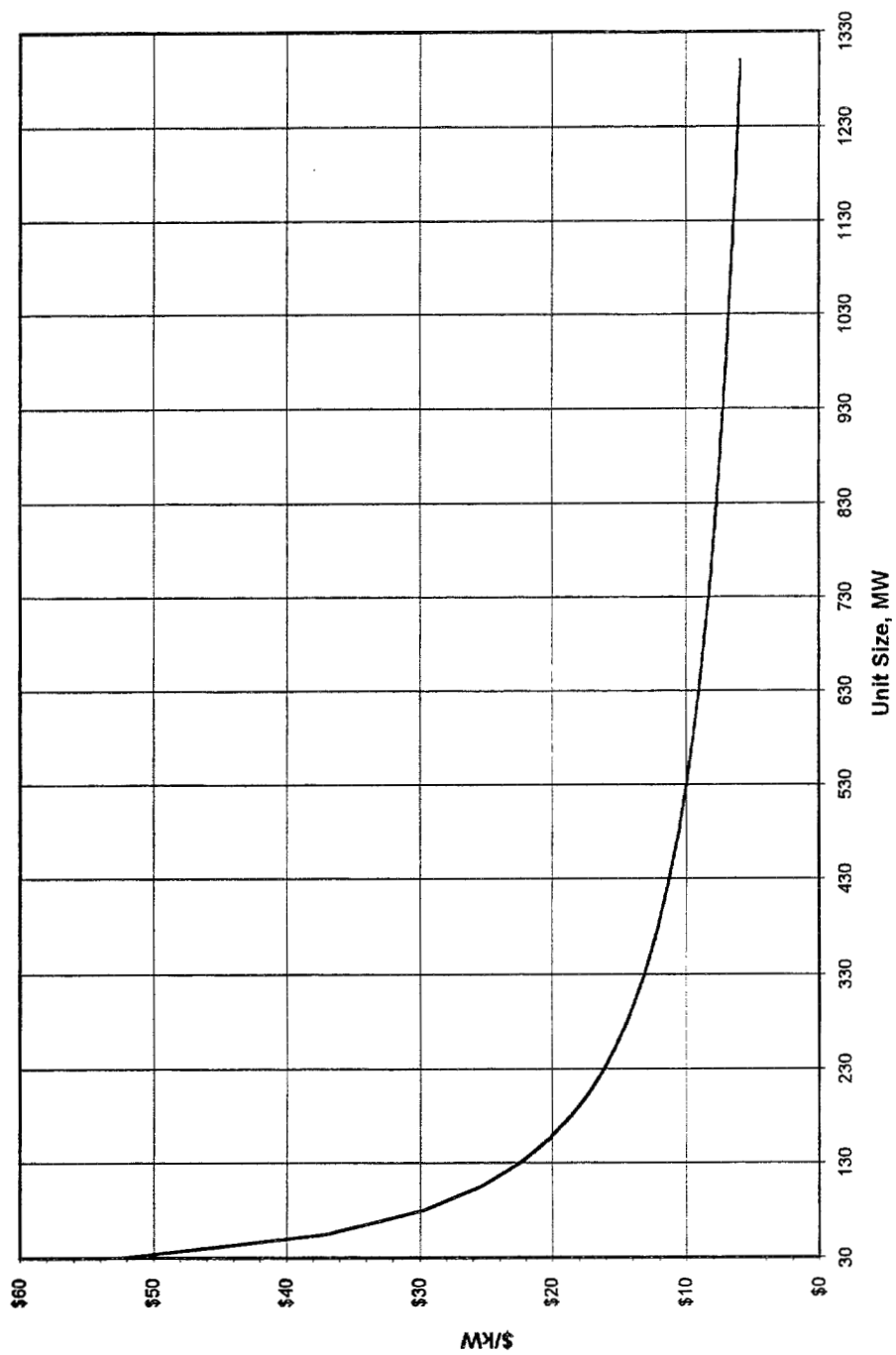**Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case**
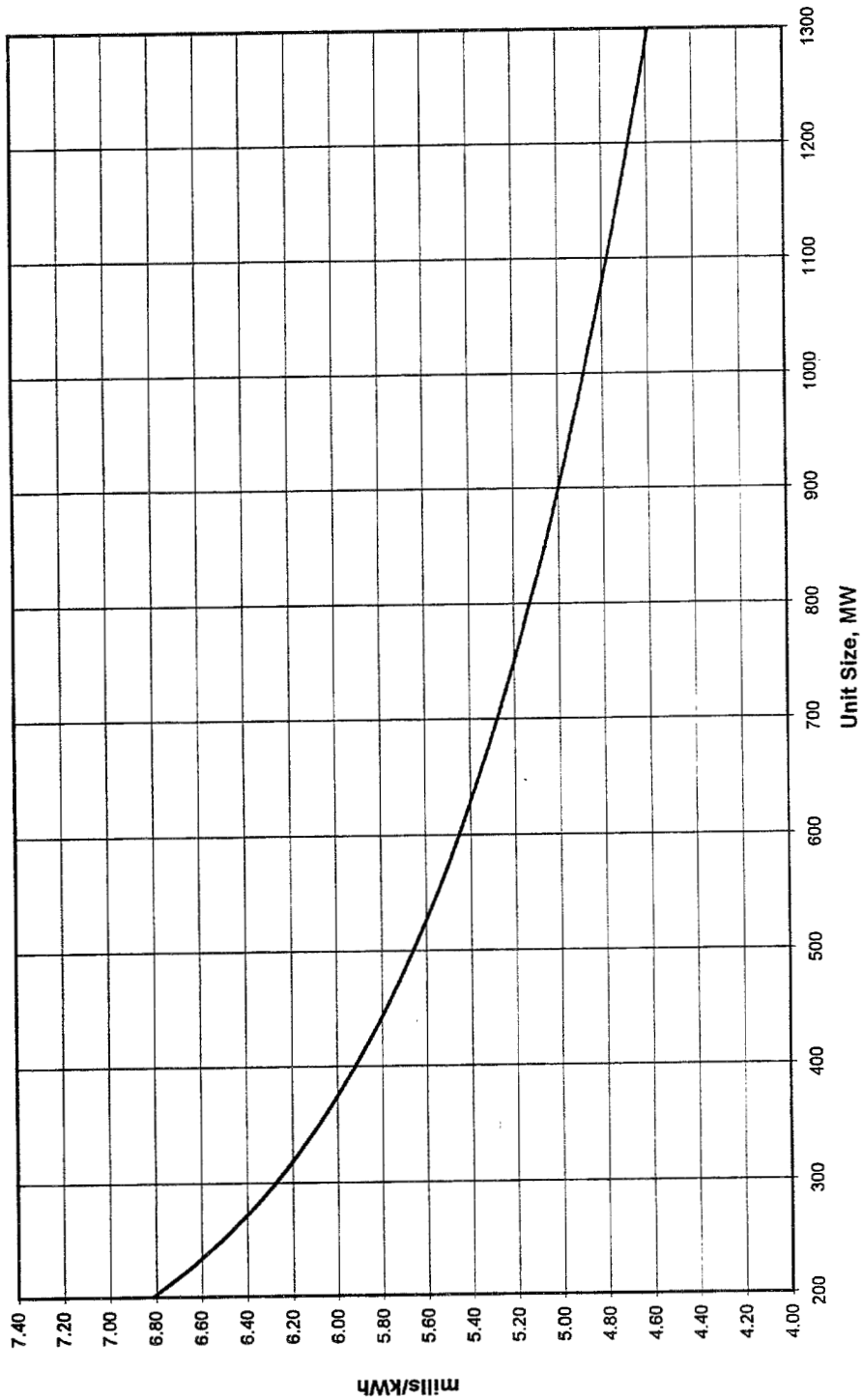
Figure 3-25
Coal-Fired, Cell Burner Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case

Figure 3-26
Cyclone-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW
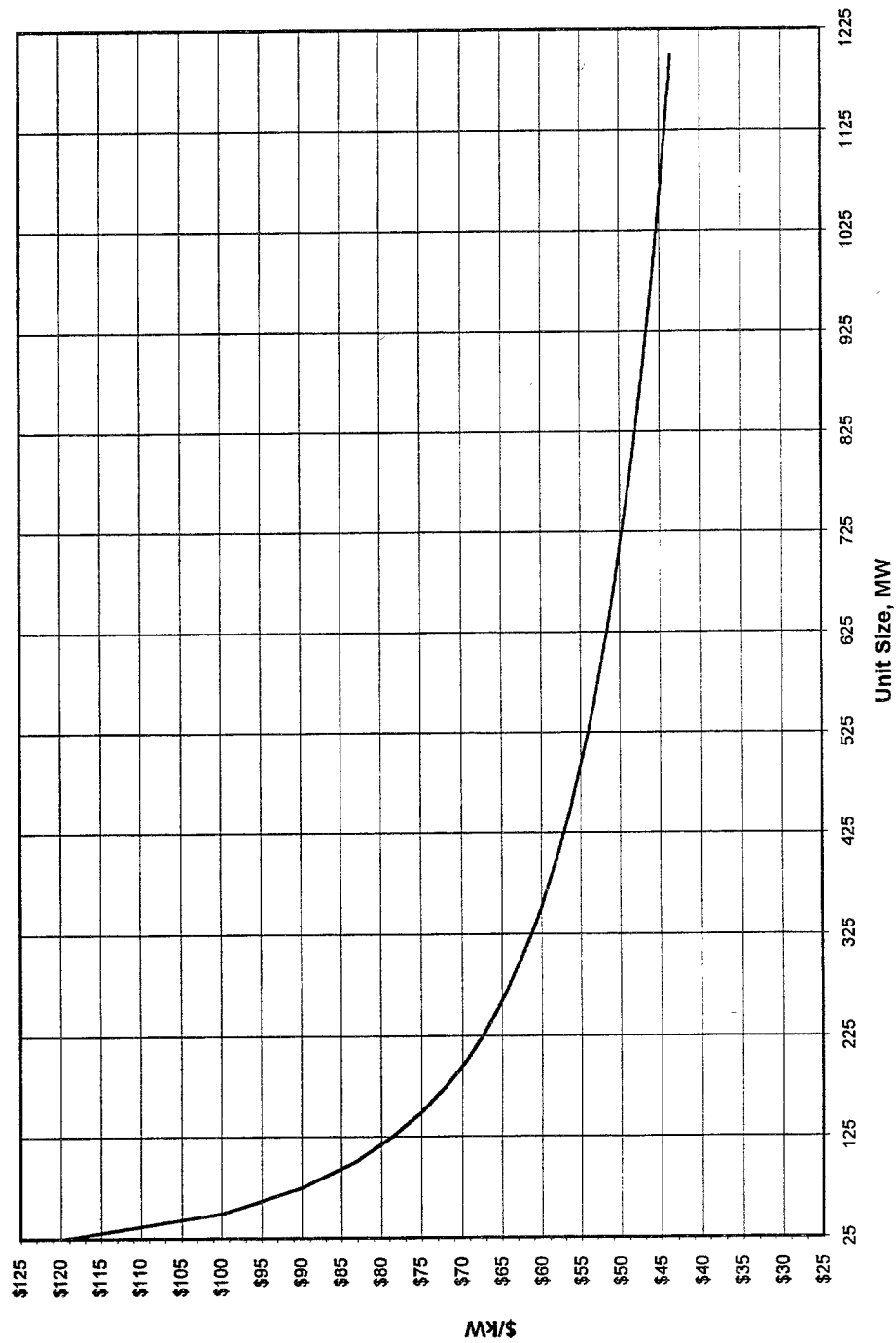
Figure 3-27
Cyclone-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
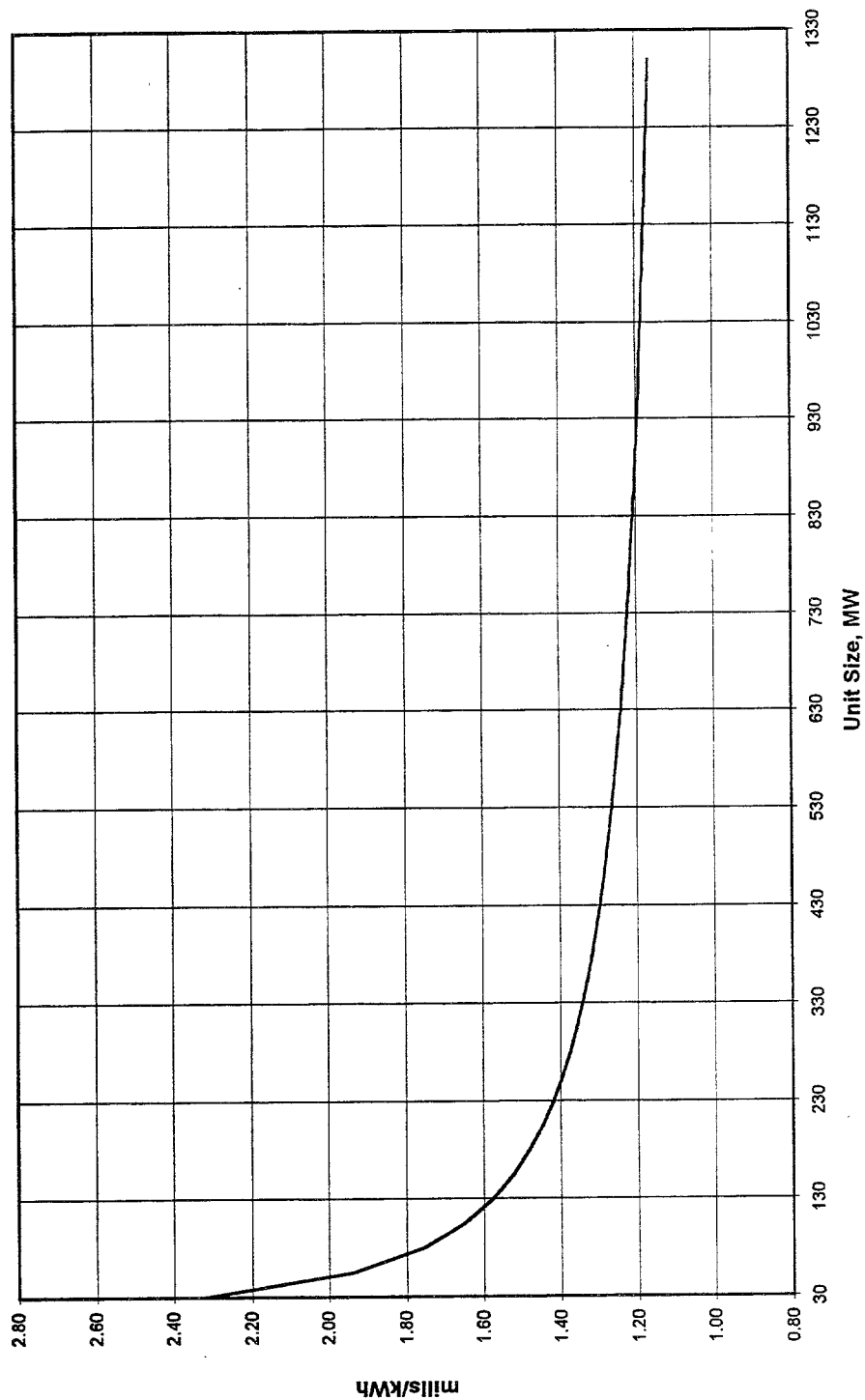Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
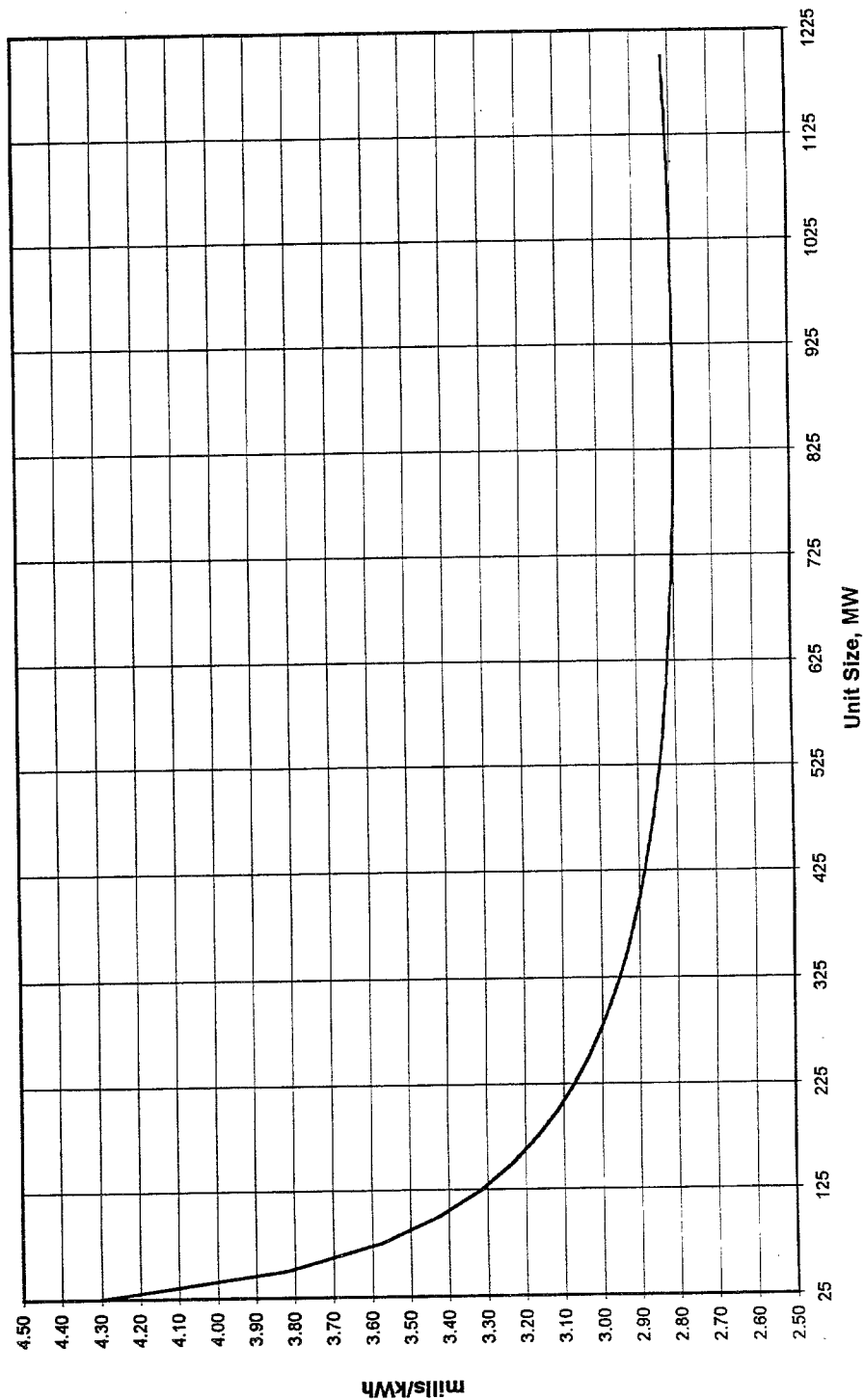
Figure 3-28
Cyclone-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
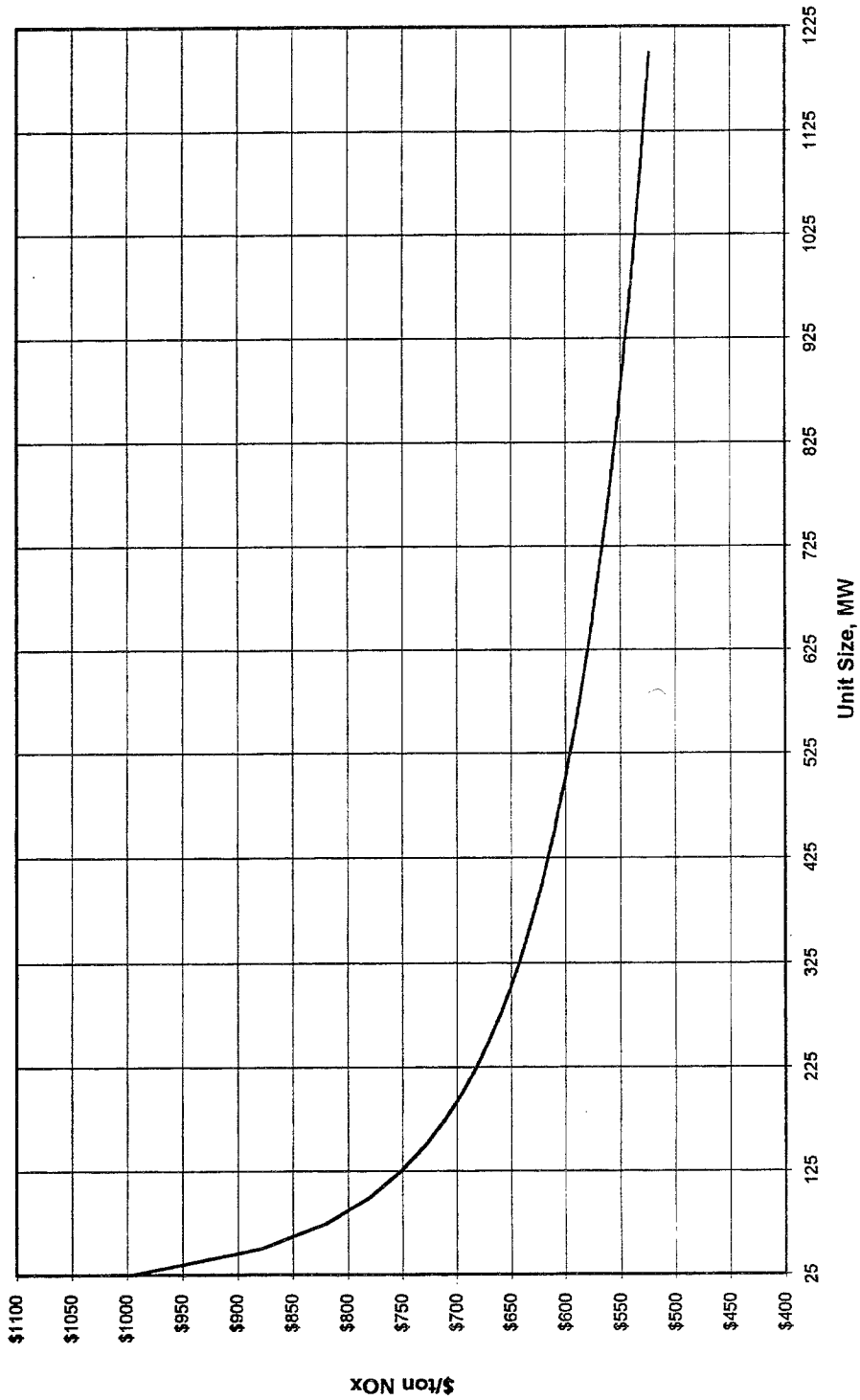
Figure 3-29
Cyclone-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
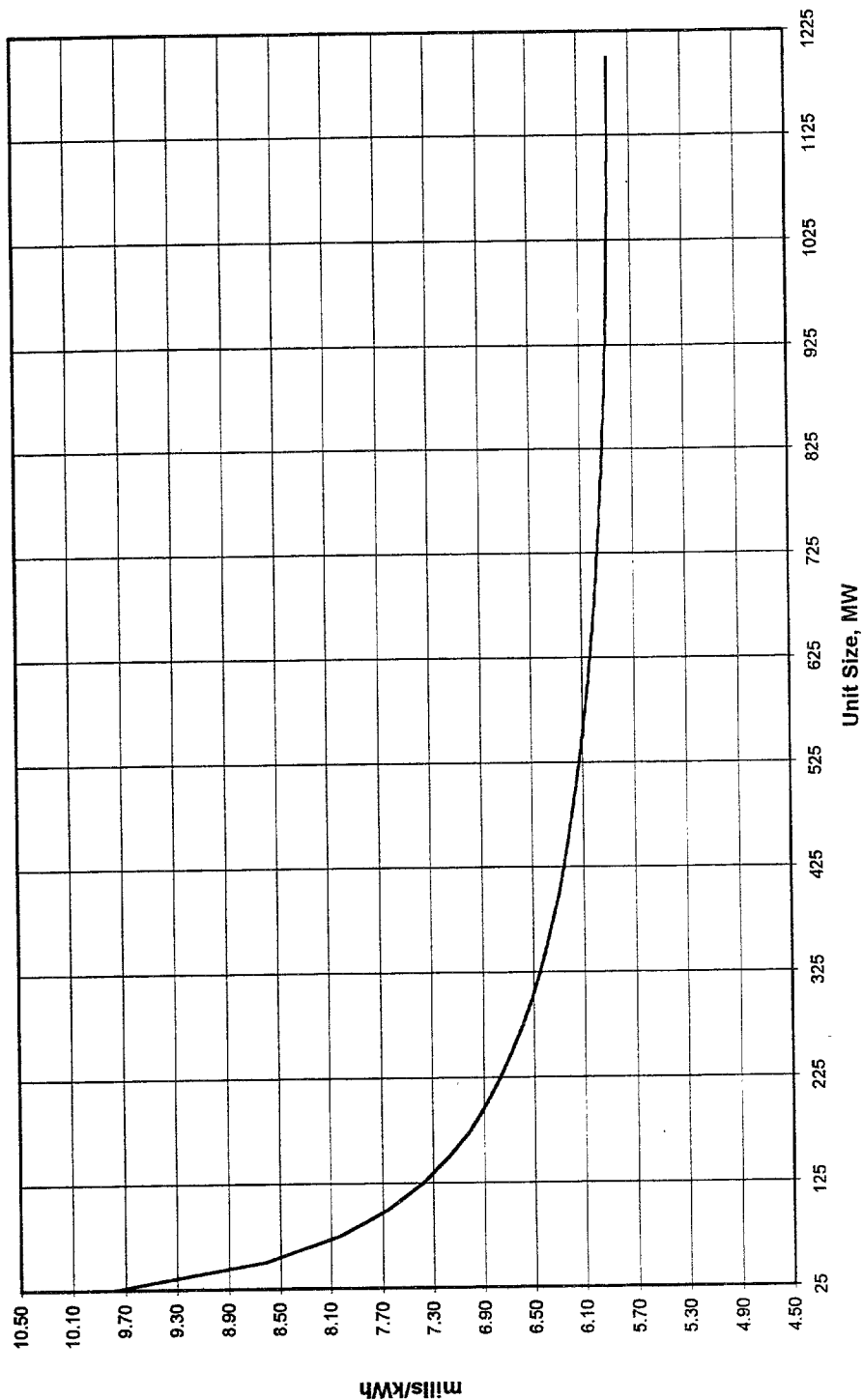
Figure 3-30
Cyclone-Fired Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
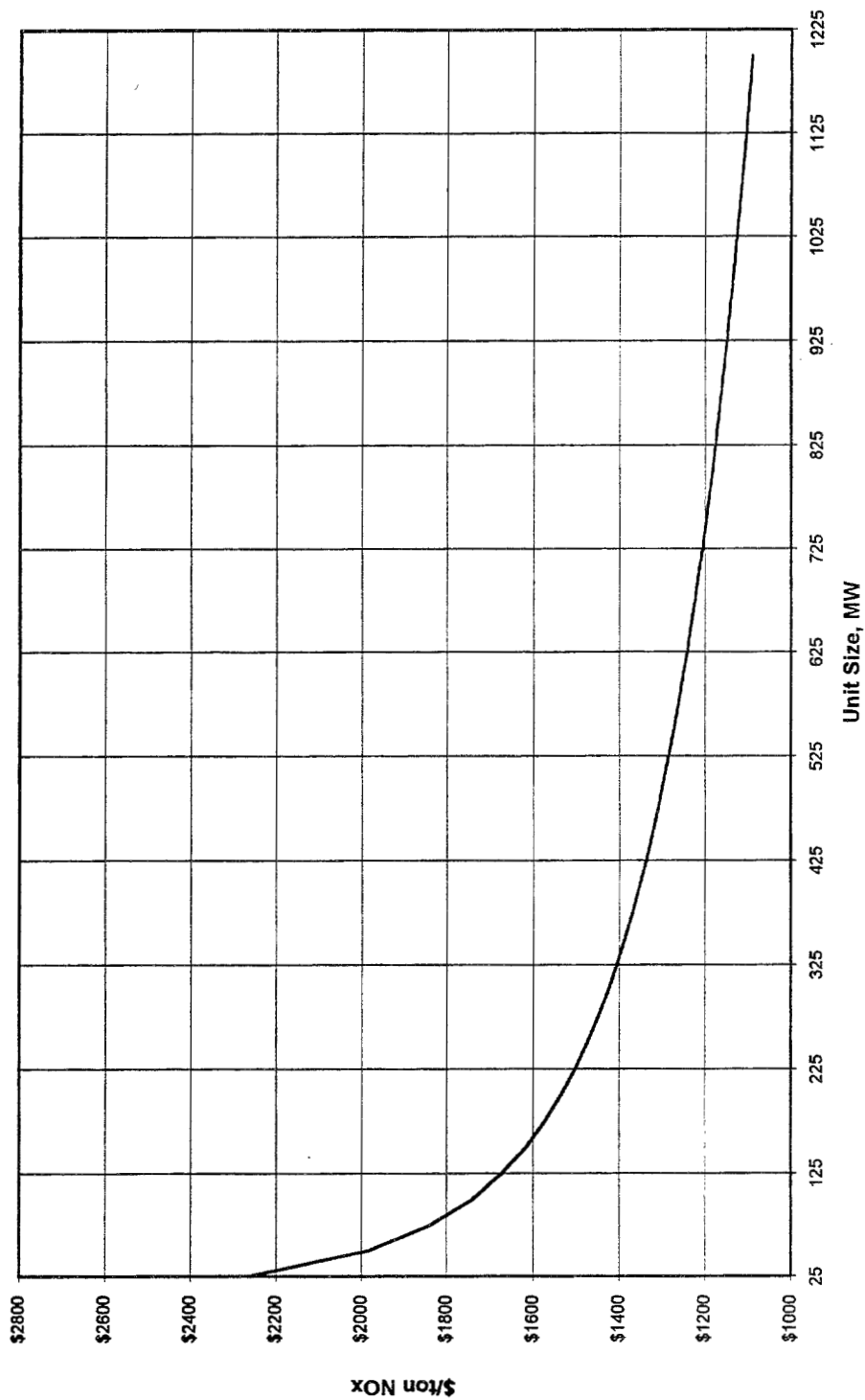
Figure 3-31
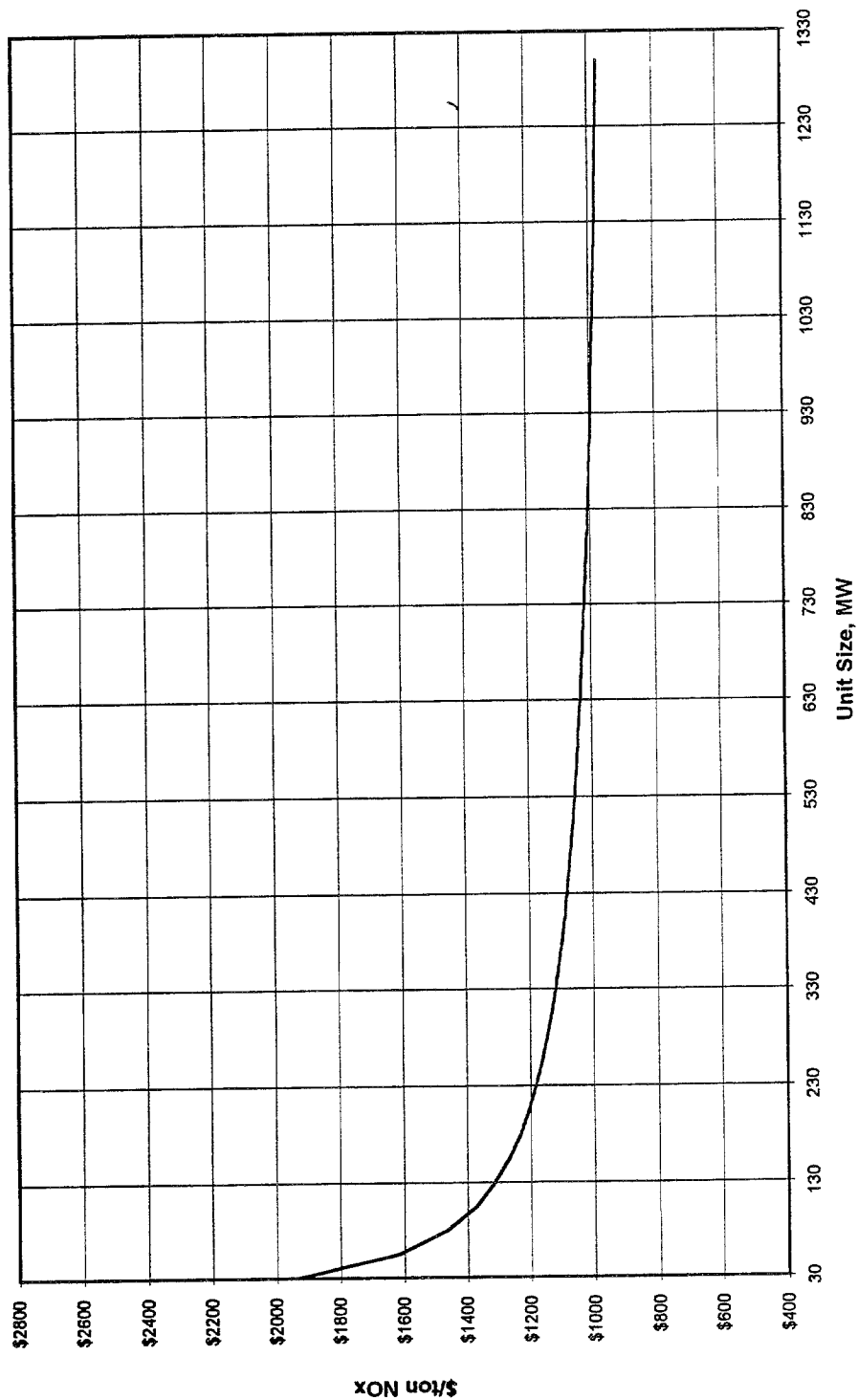Wet Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW

Figure 3-32
Wet Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
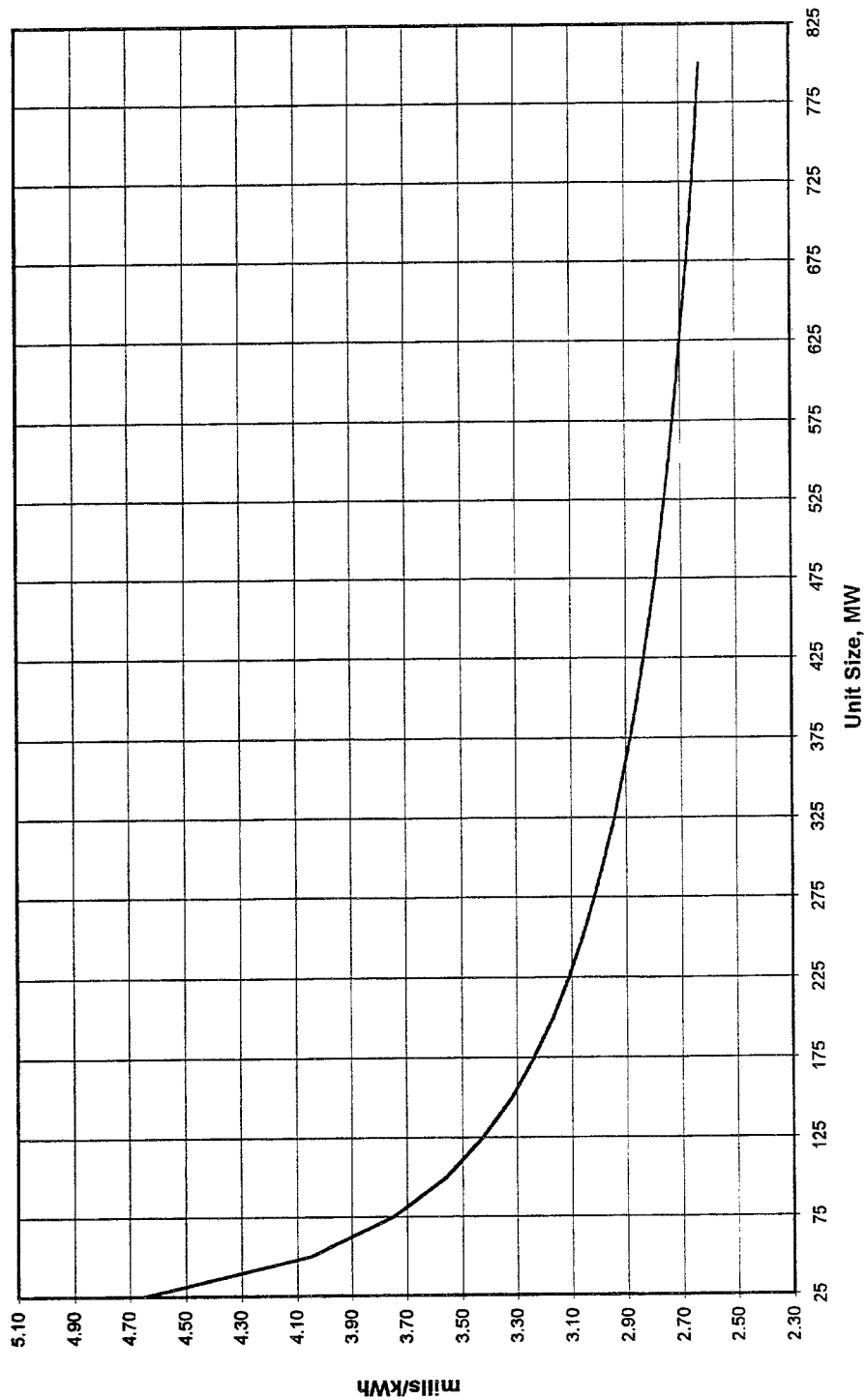
Figure 3-33
Wet Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
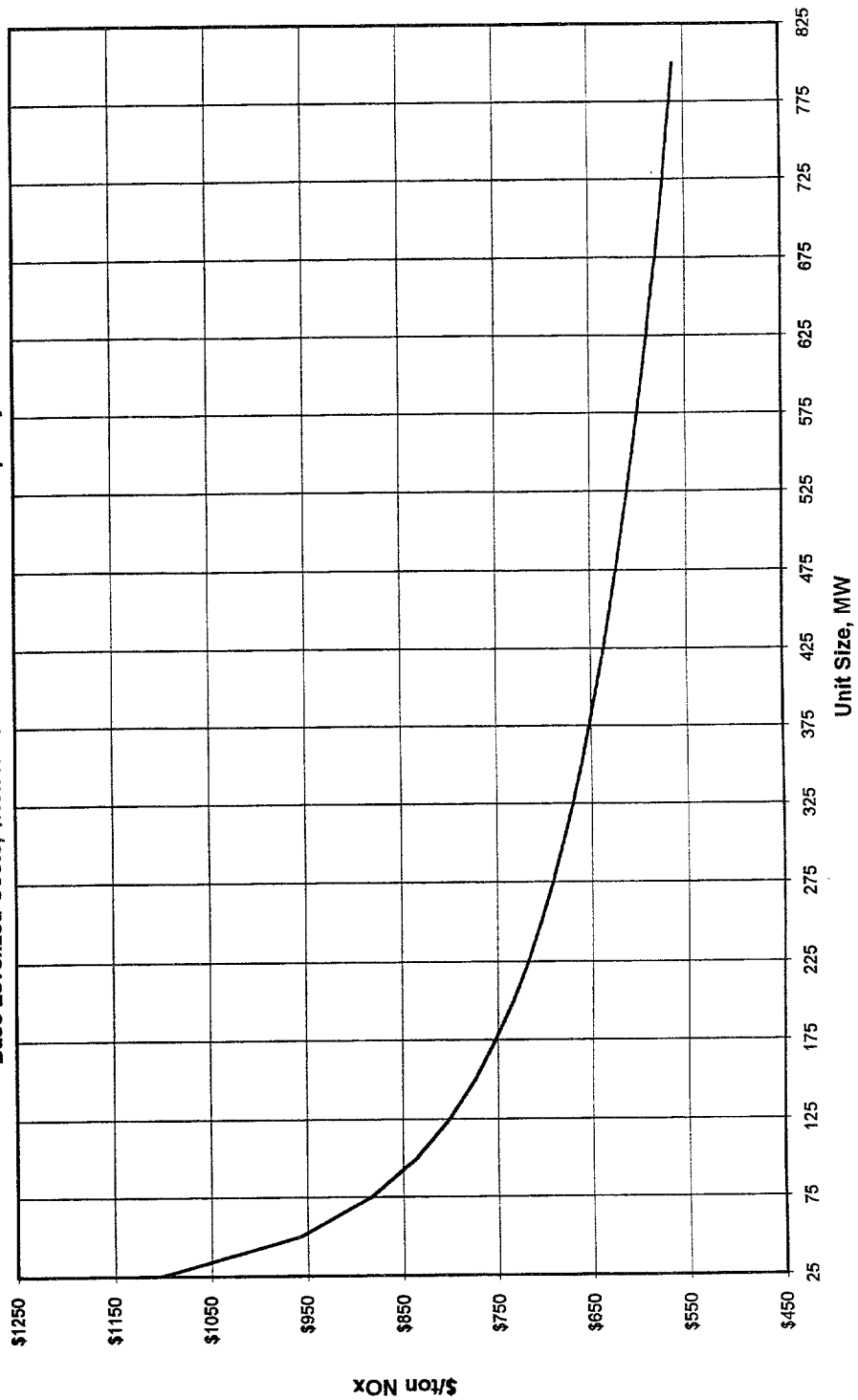
Figure 3-34
Wet Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW – 27% Capacity Factor Case
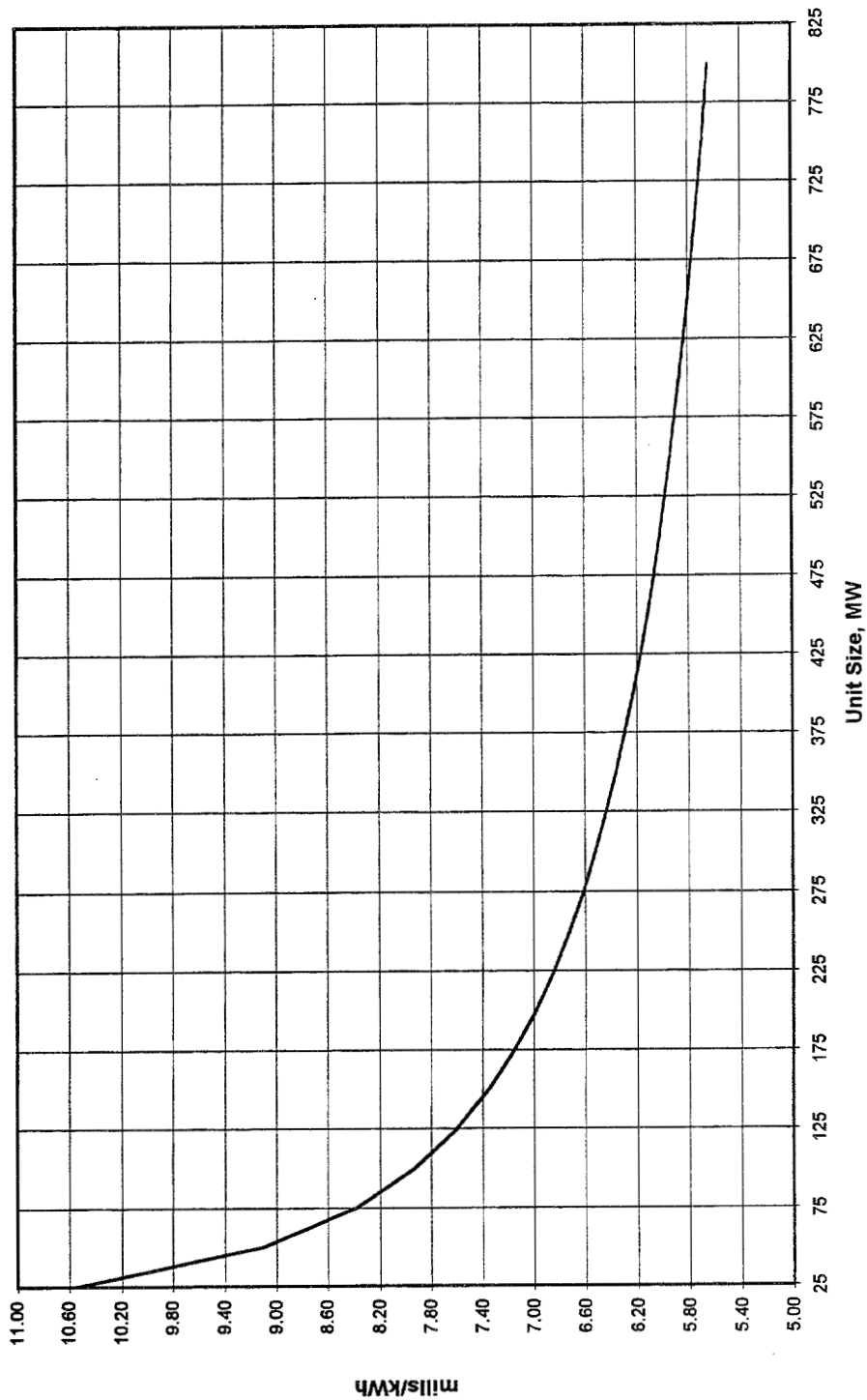
Figure 3-35
Wet Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
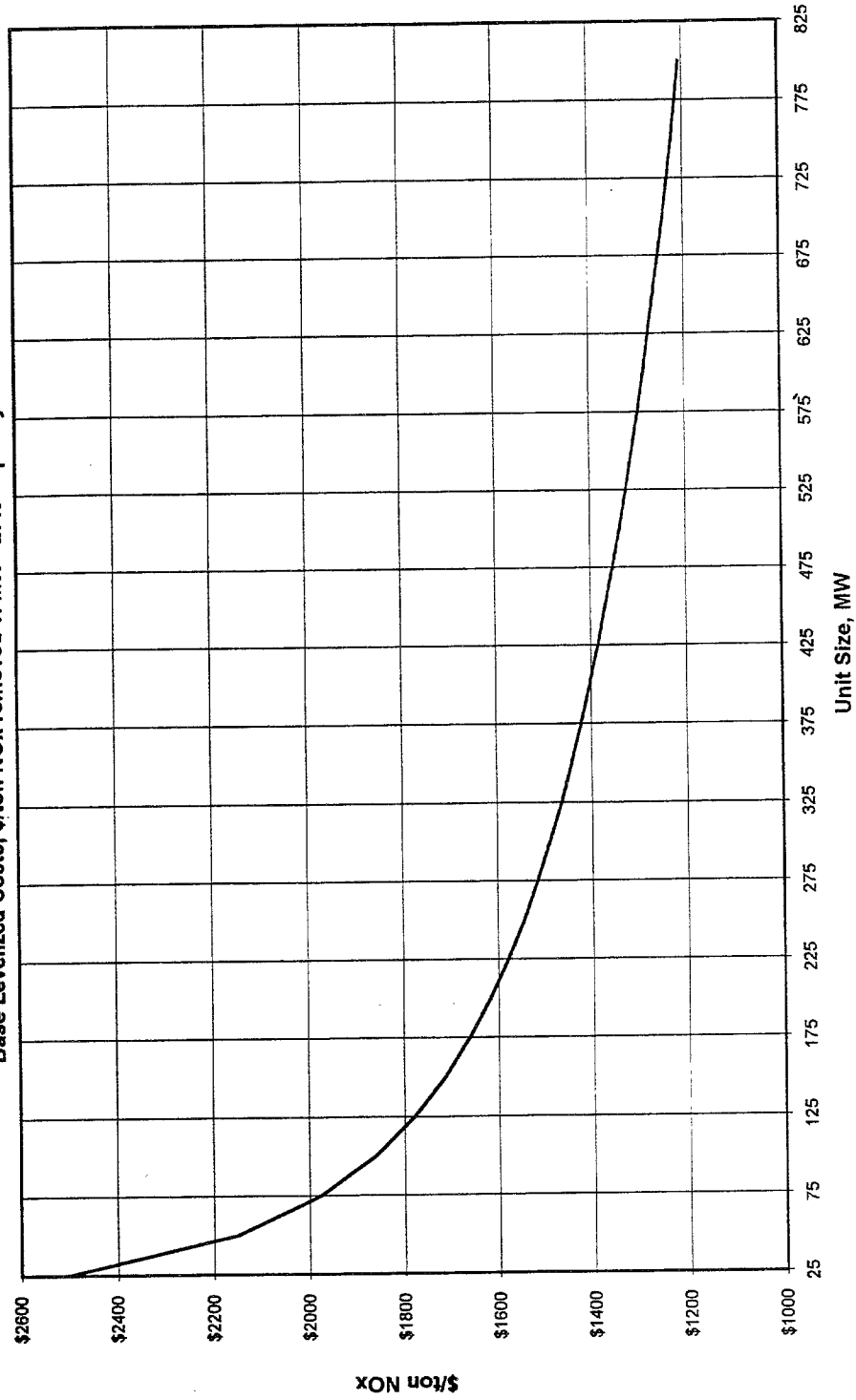
Figure 3-36
Vertically-Fired Dry Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW

Figure 3-37
Vertically-Fired Dry Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
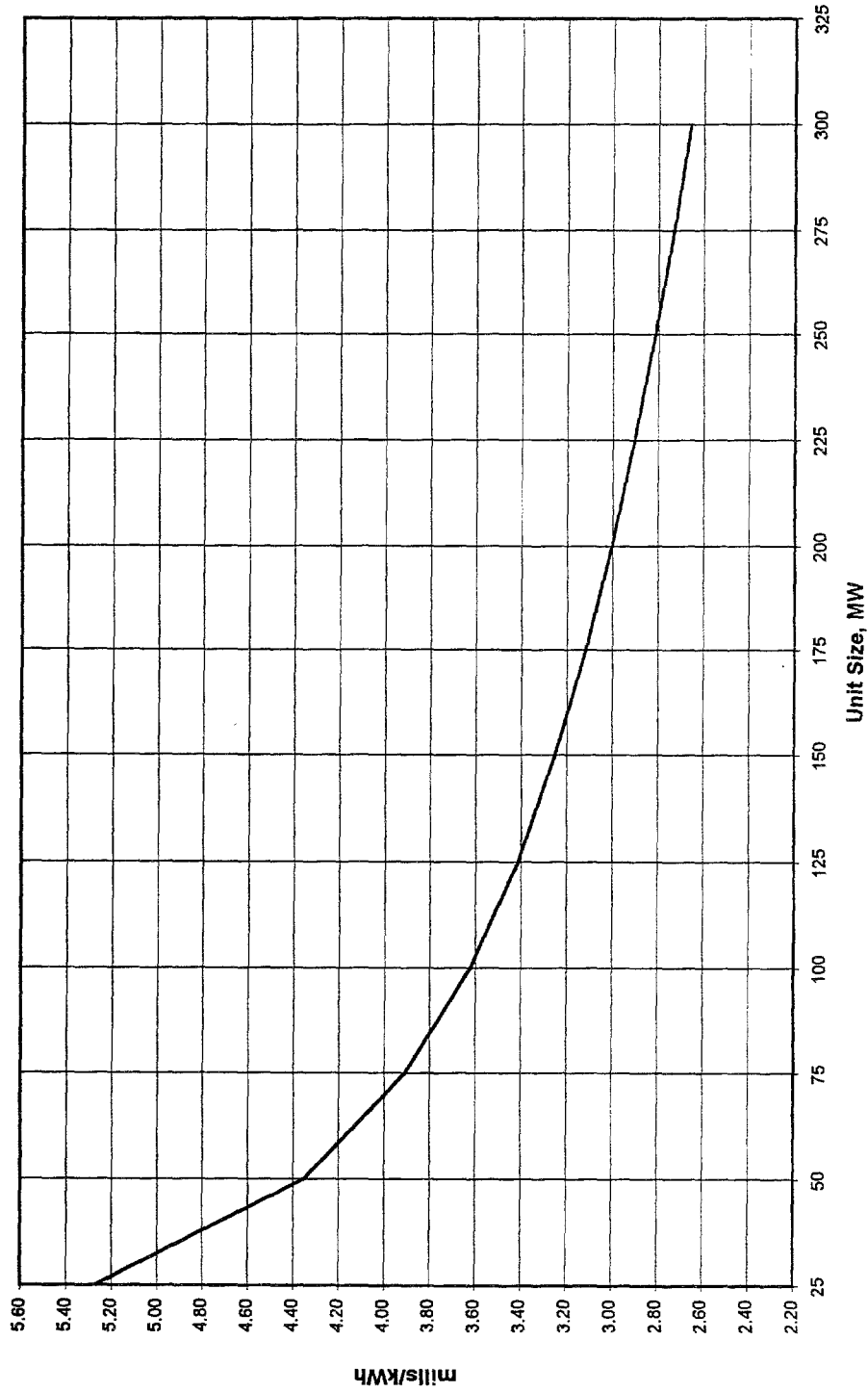
Figure 3-38
Vertically-Fired Dry Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
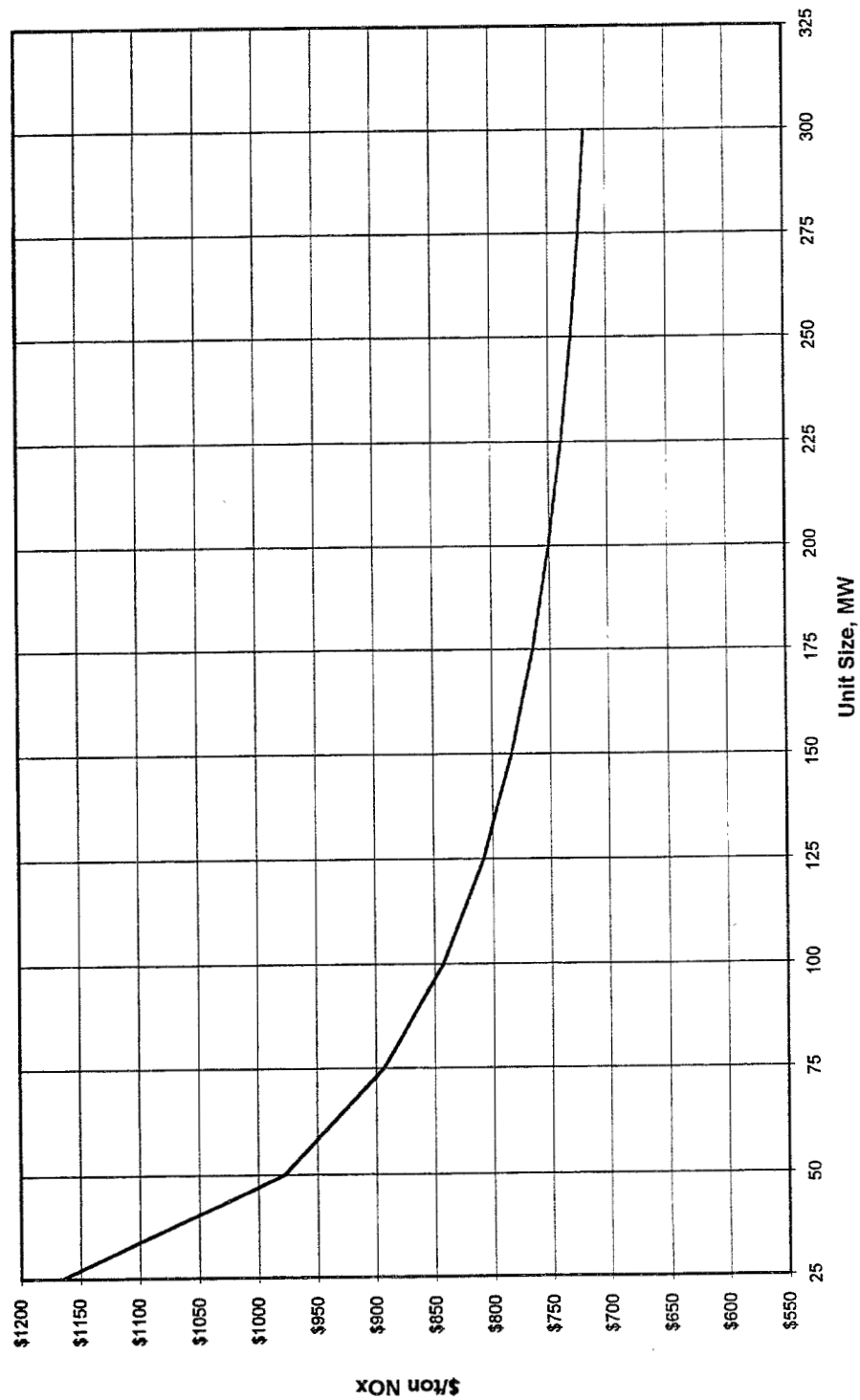
Figure 3-39
Vertically-Fired Dry Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
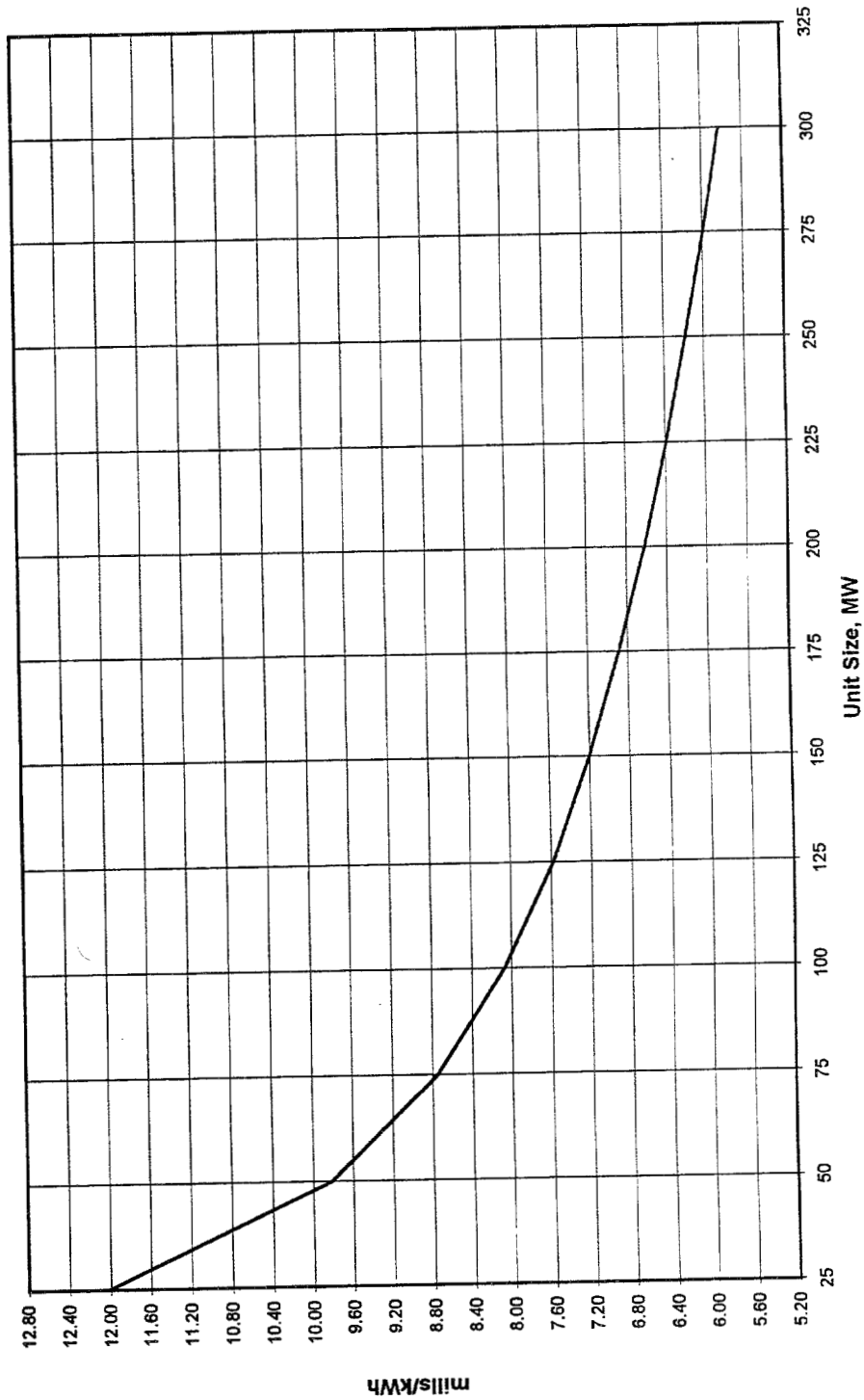
Figure 3-40
Vertically-Fired Dry Bottom Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case

Figures 4-1 through 4-15

Figure 4-1
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Capital Costs v. MW
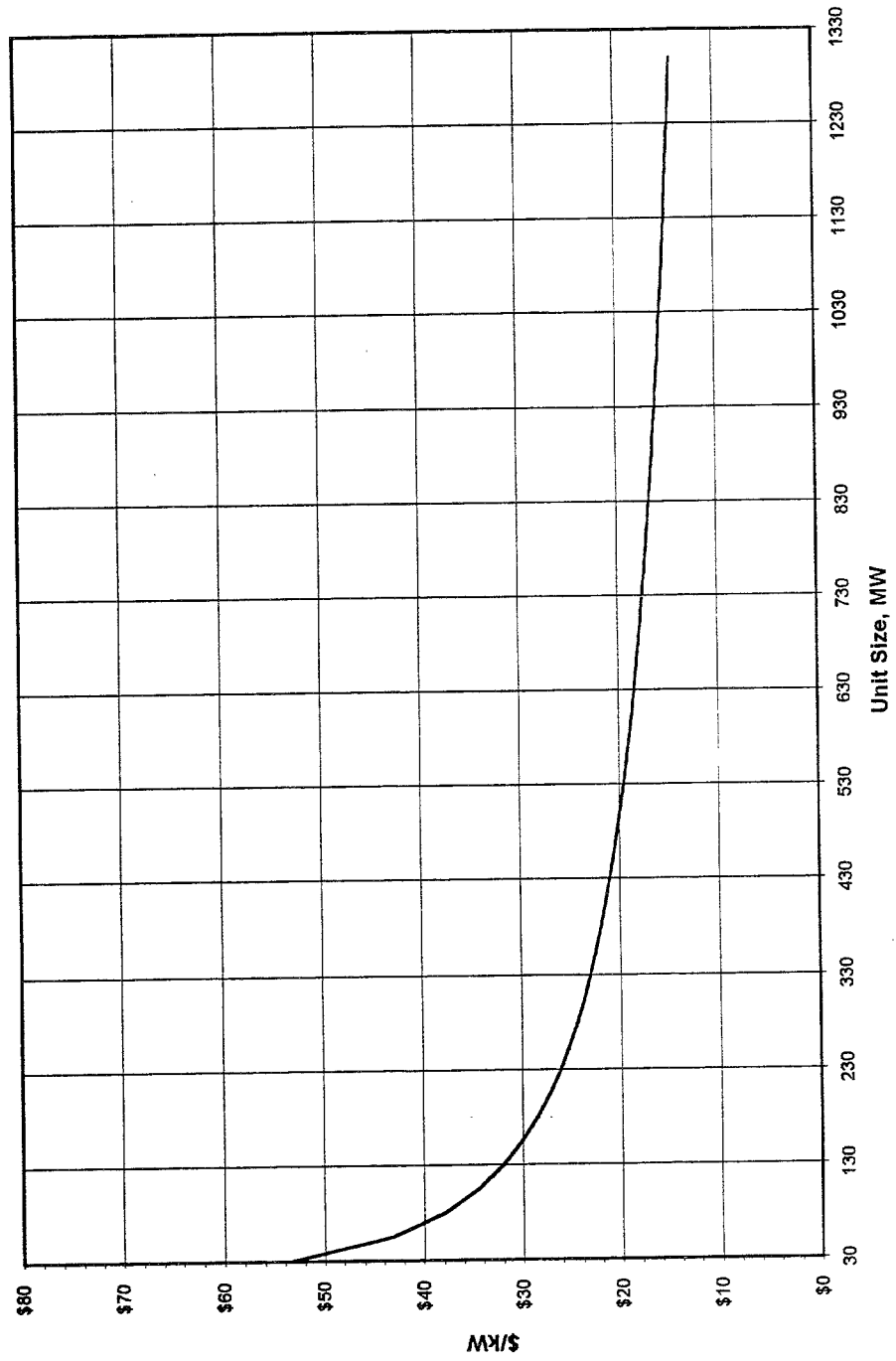
Figure 4-2
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case

mills/kWh

Unit Size, MW
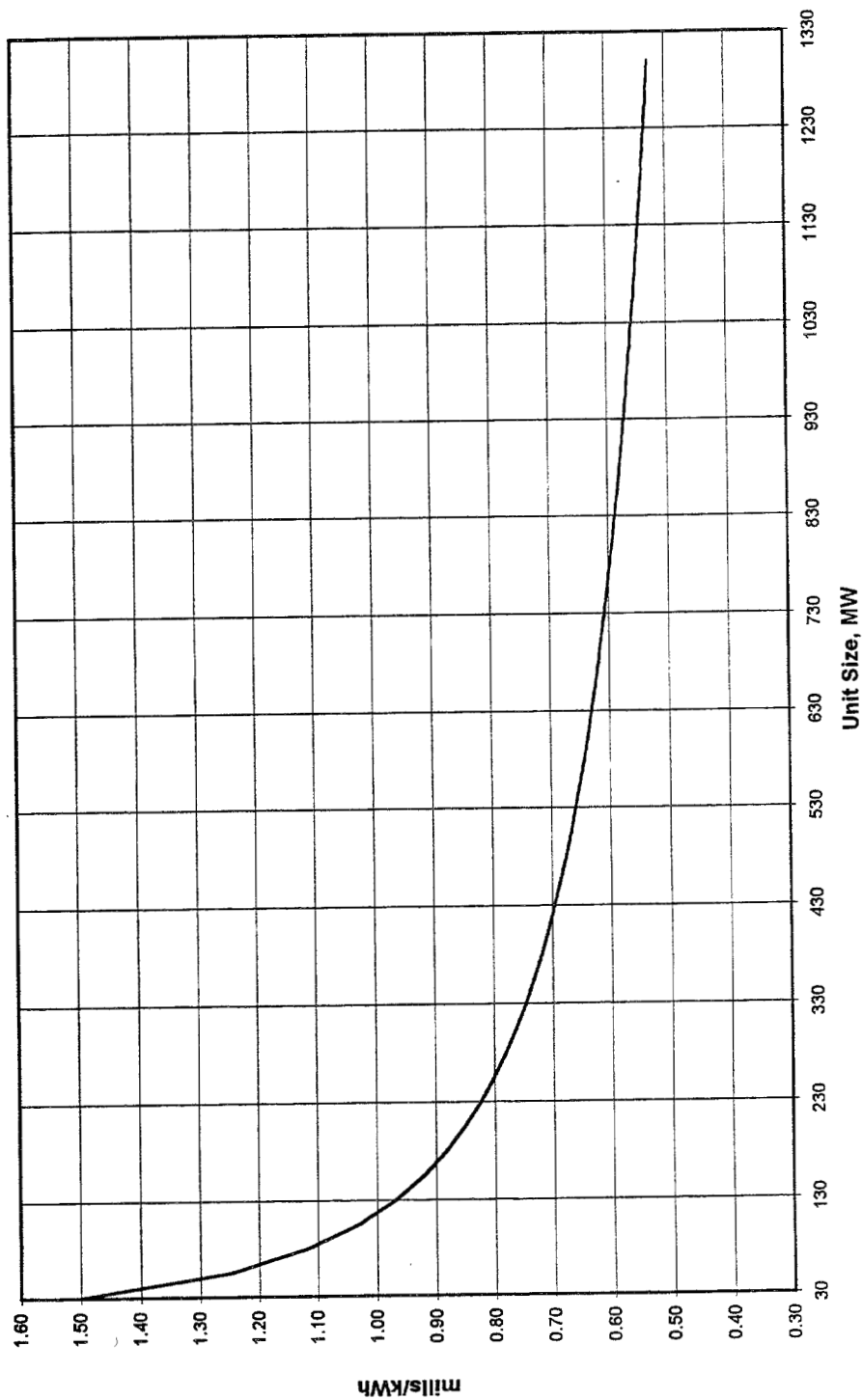
Figure 4-3
Gas-Fired, Wall-Burner or Tangential, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
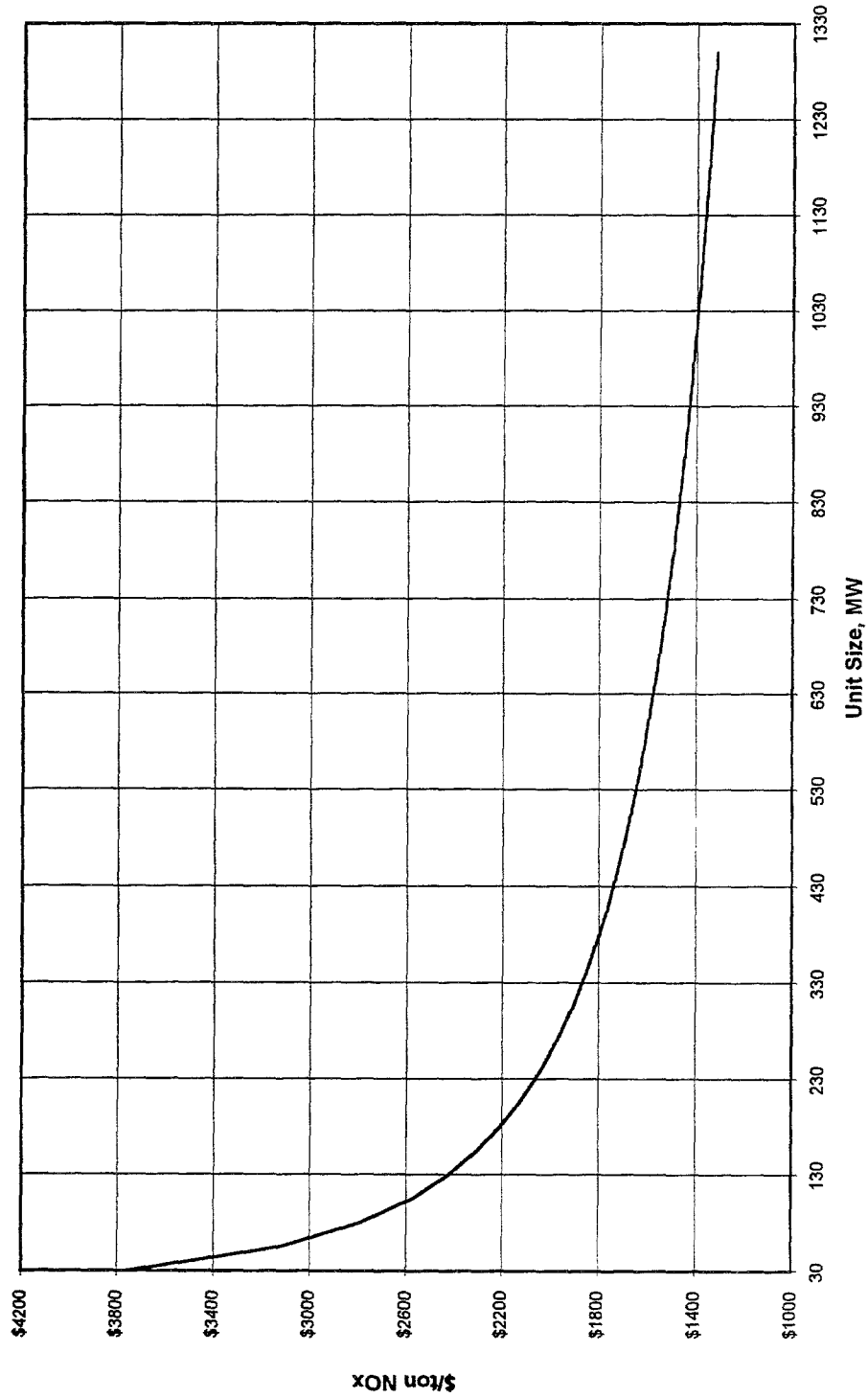
Figure 4-4

**Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case**
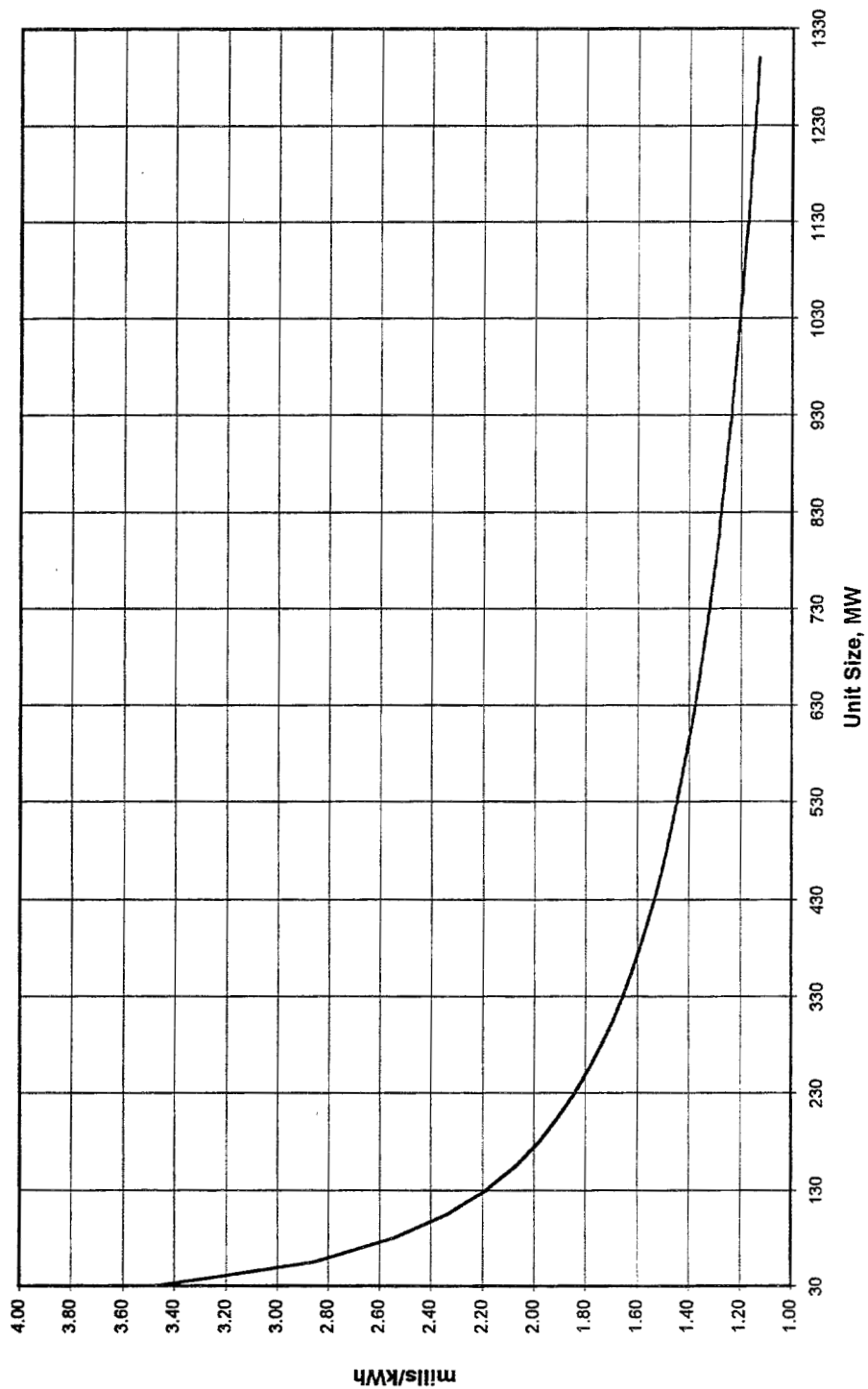
Figure 4-5
Gas-Fired, Wall-Burner or Tangential, 0.15 Lb/MMBtu SCR Retrofit
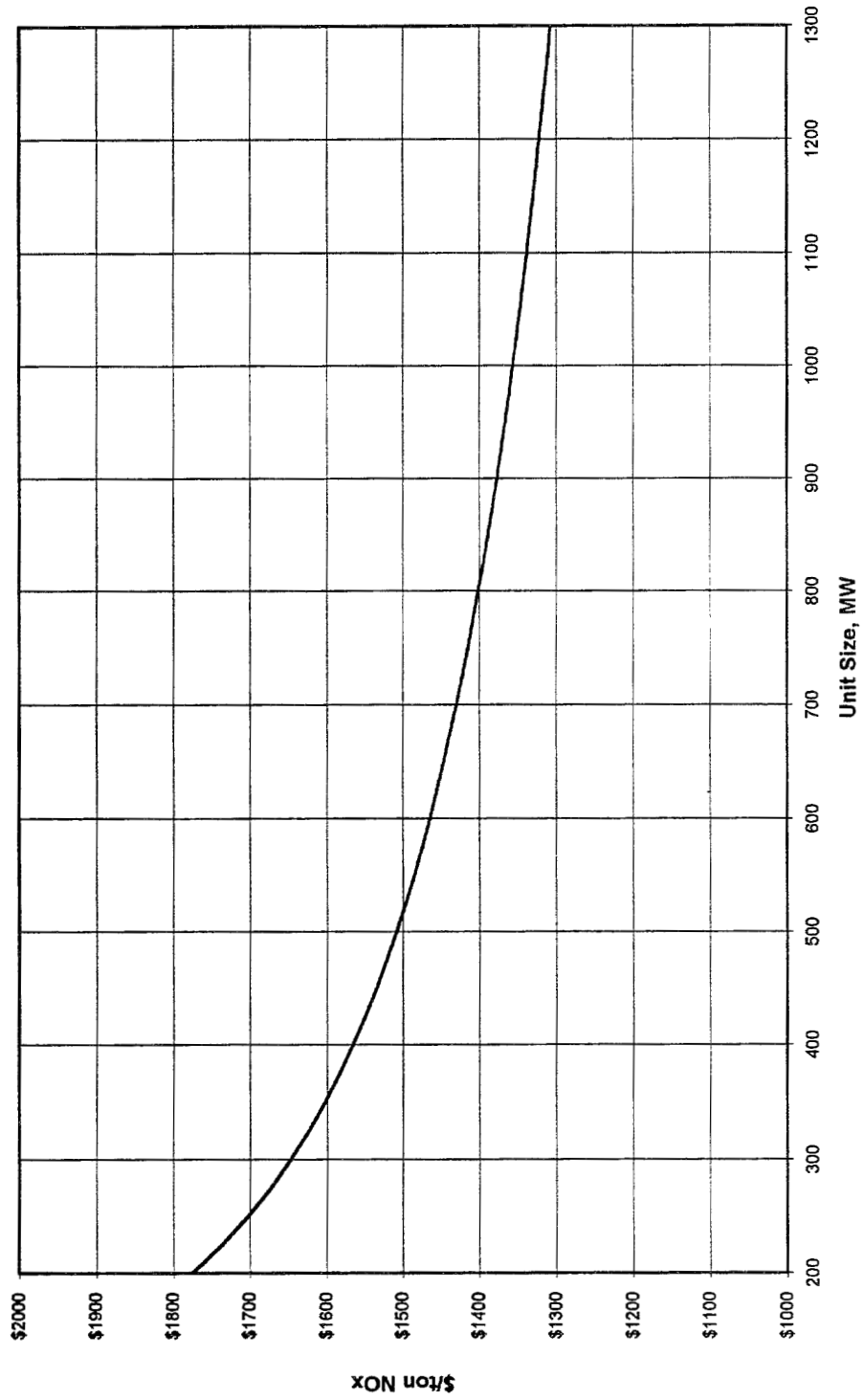**Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case**
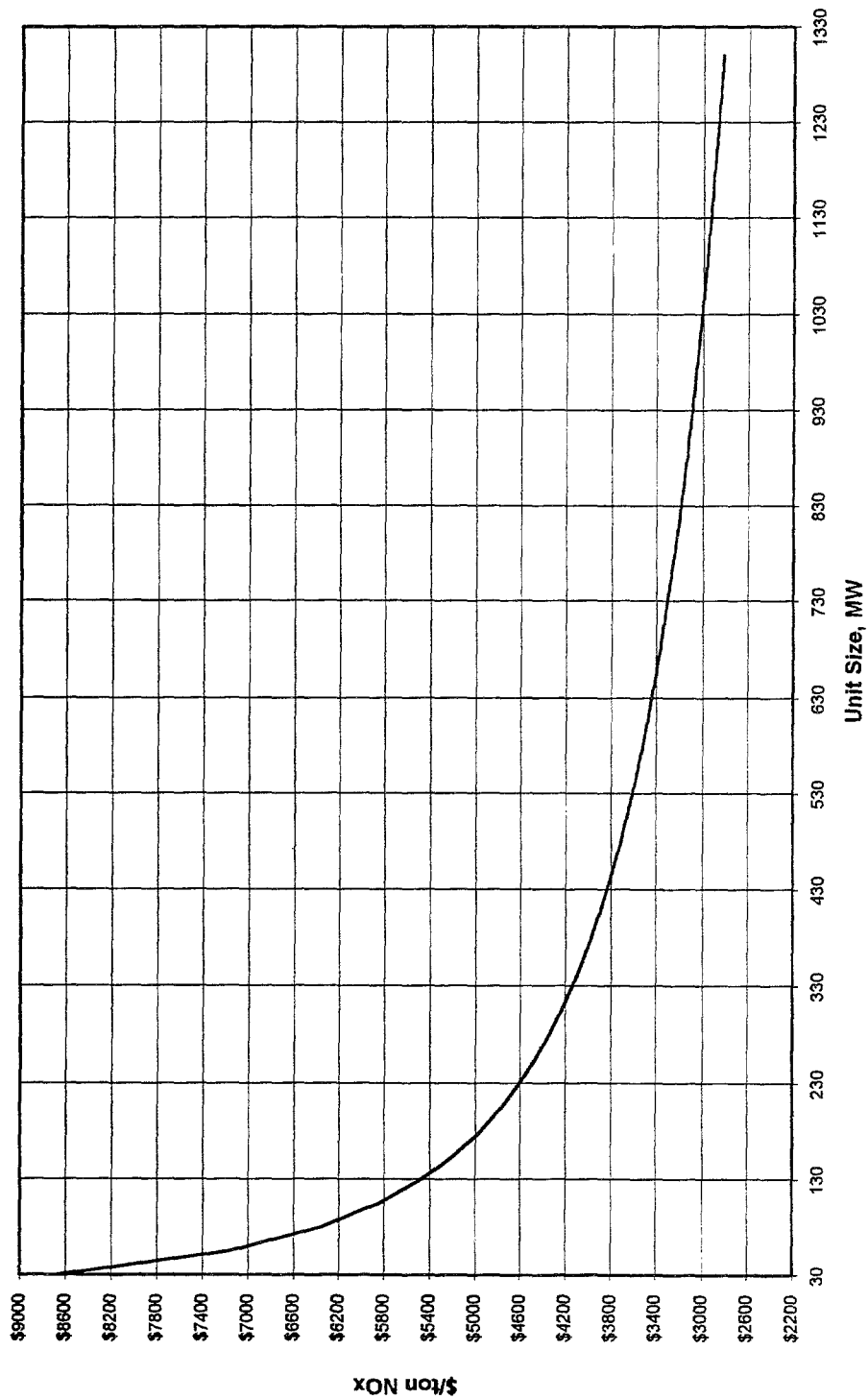
Figure 4-6
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Capital Costs v. MW
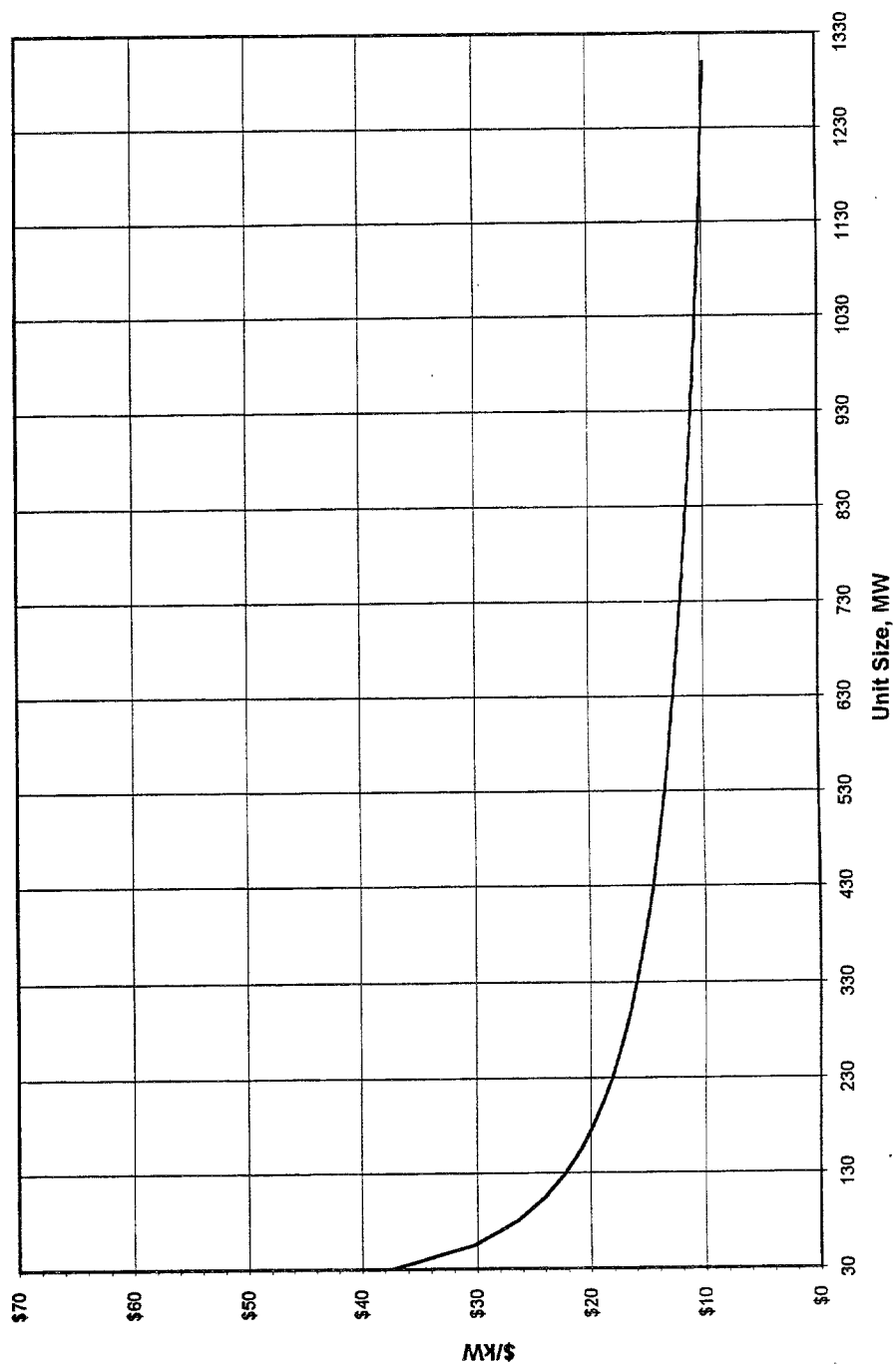
Figure 4-7
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
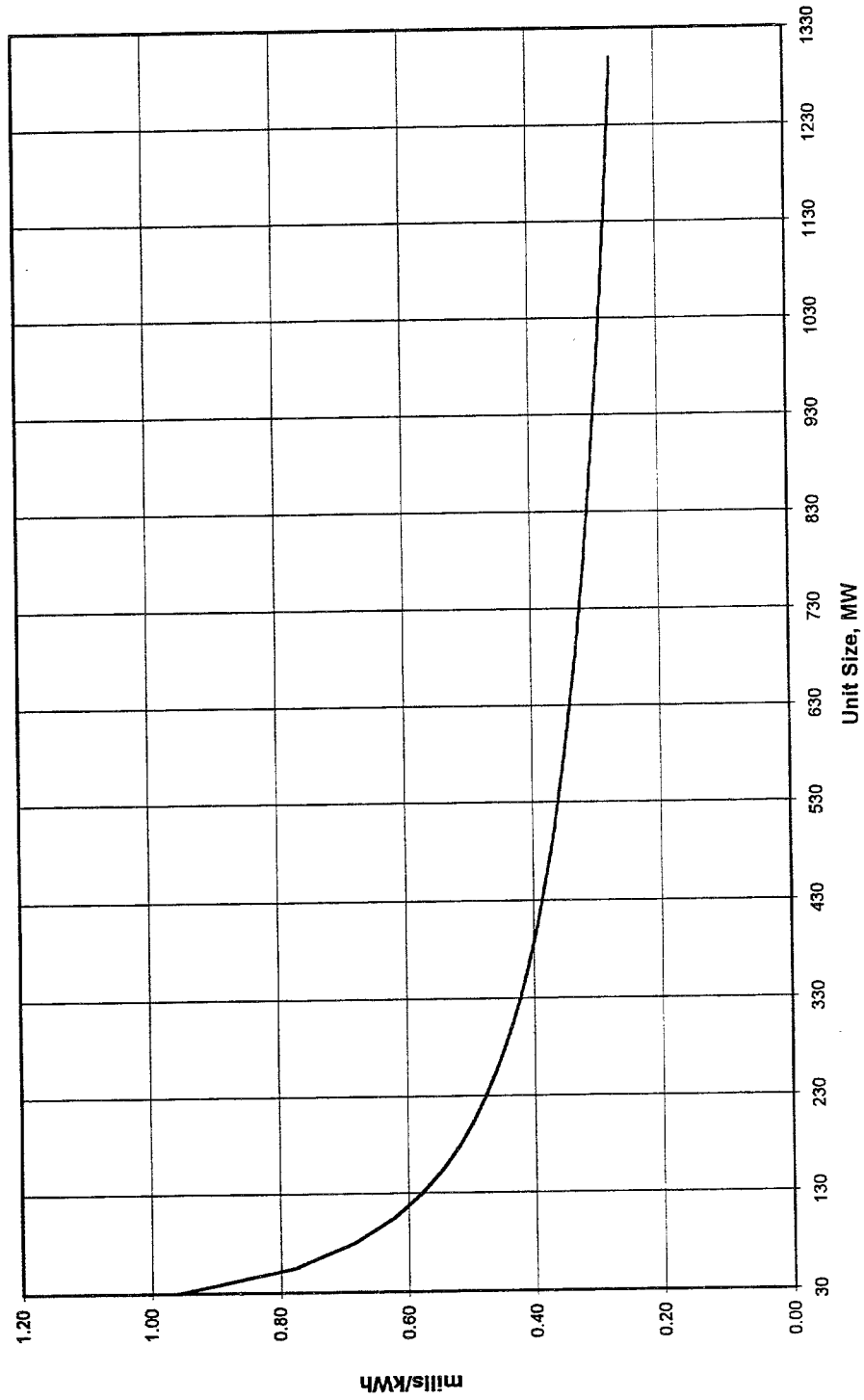
Figure 4-8
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
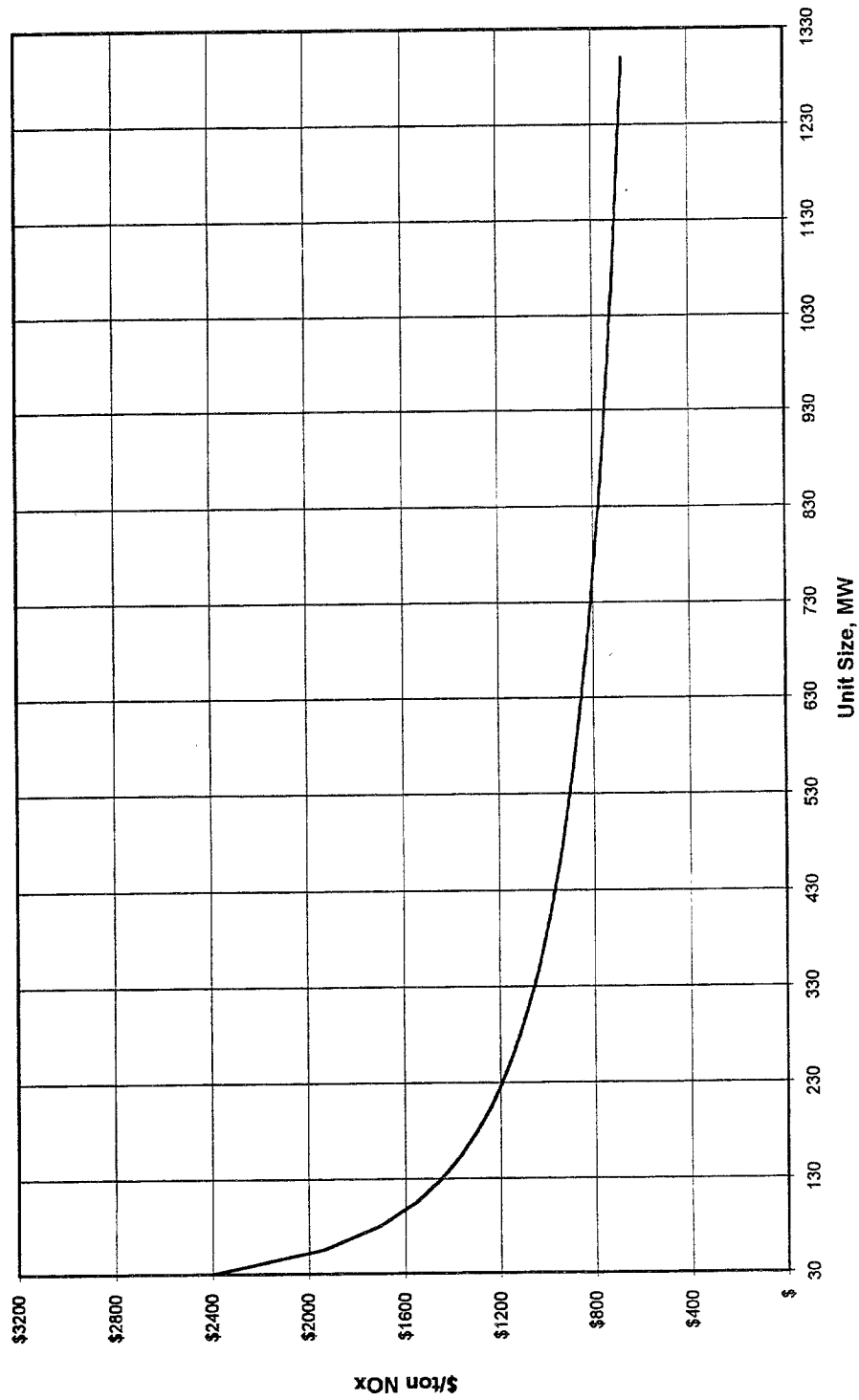
Figure 4-9
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
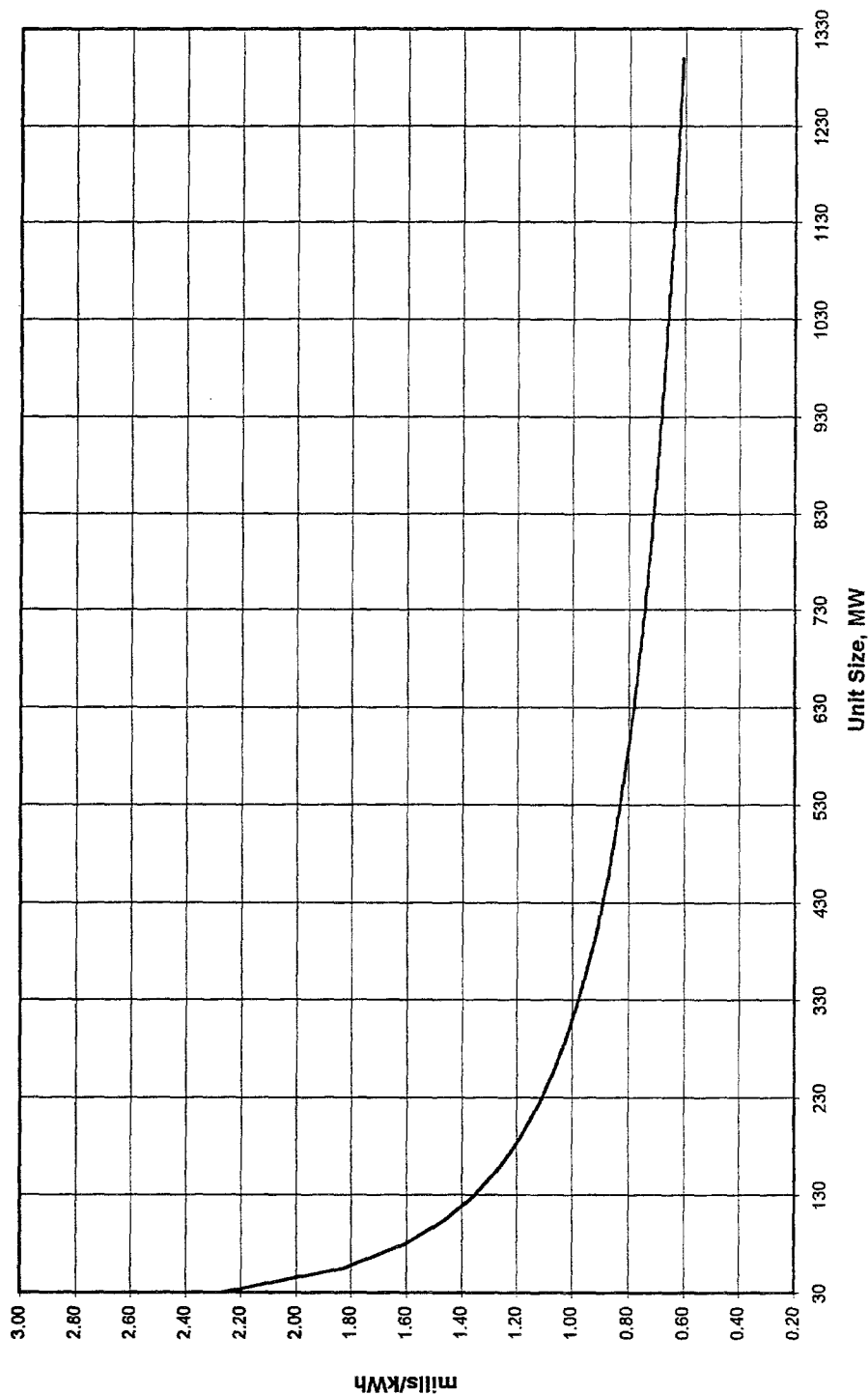
Figure 4-10

Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit

Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
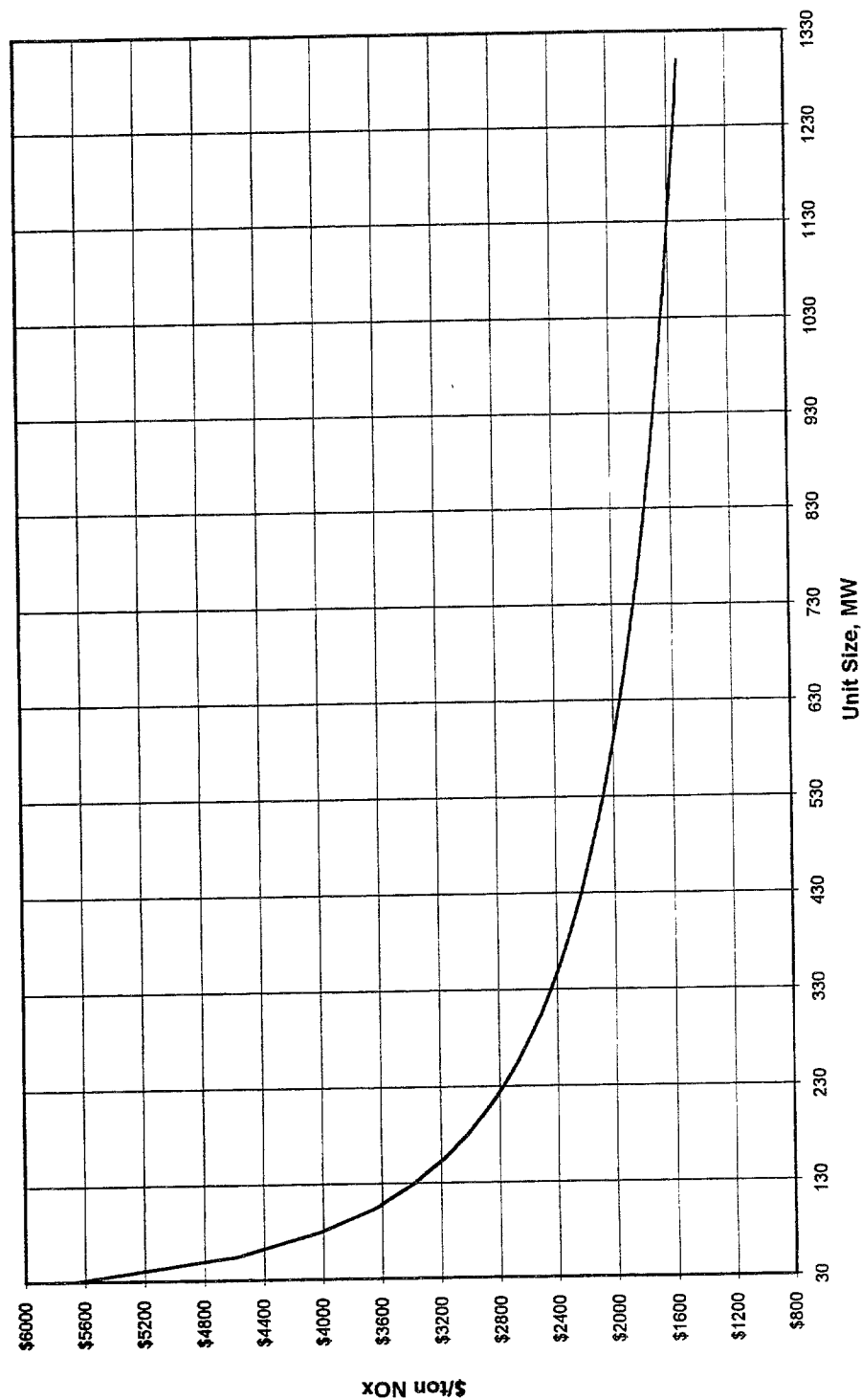
Figure 4-11

Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit

Base Capital Costs v. MW
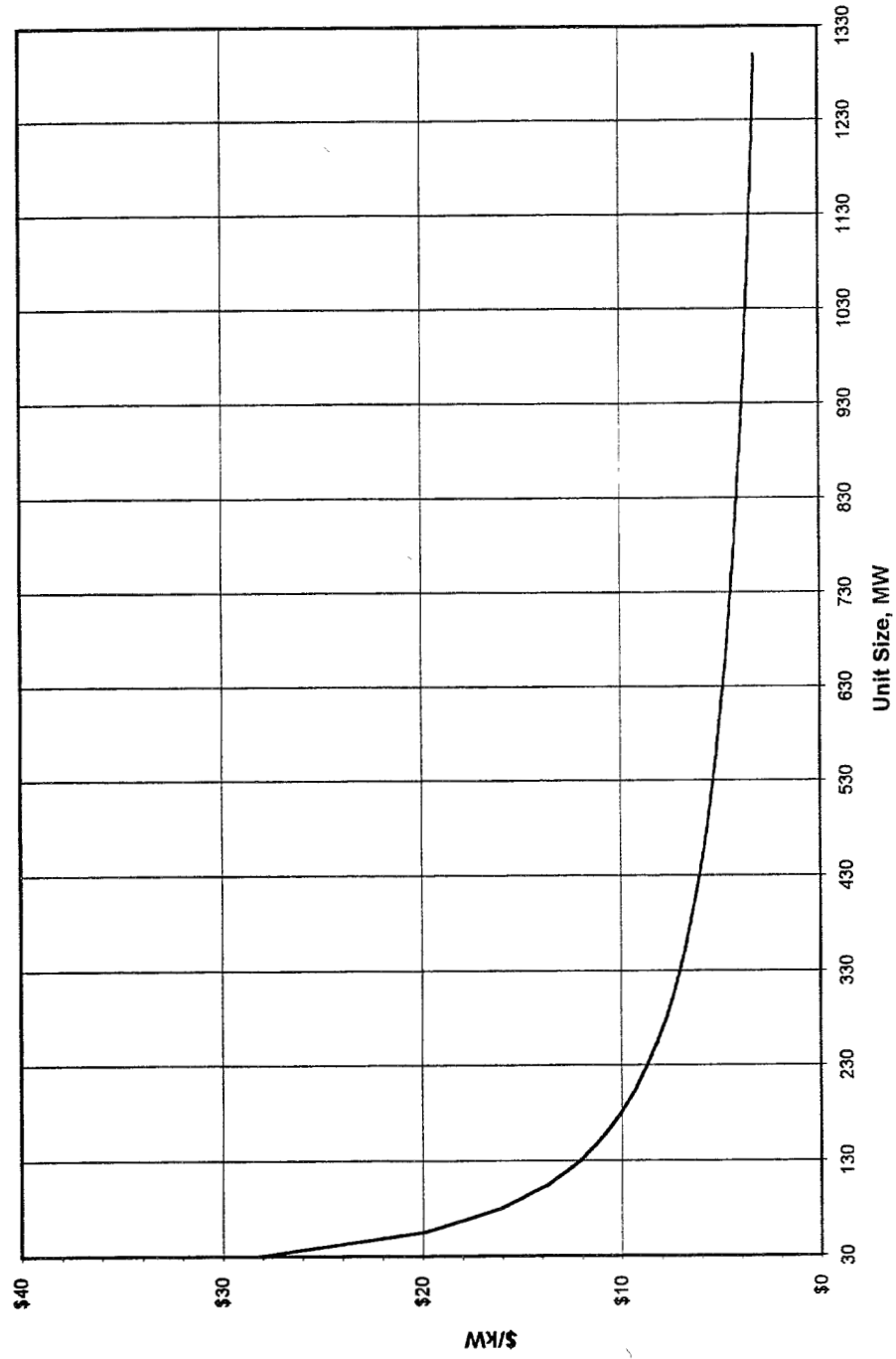
Figure 4-12
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
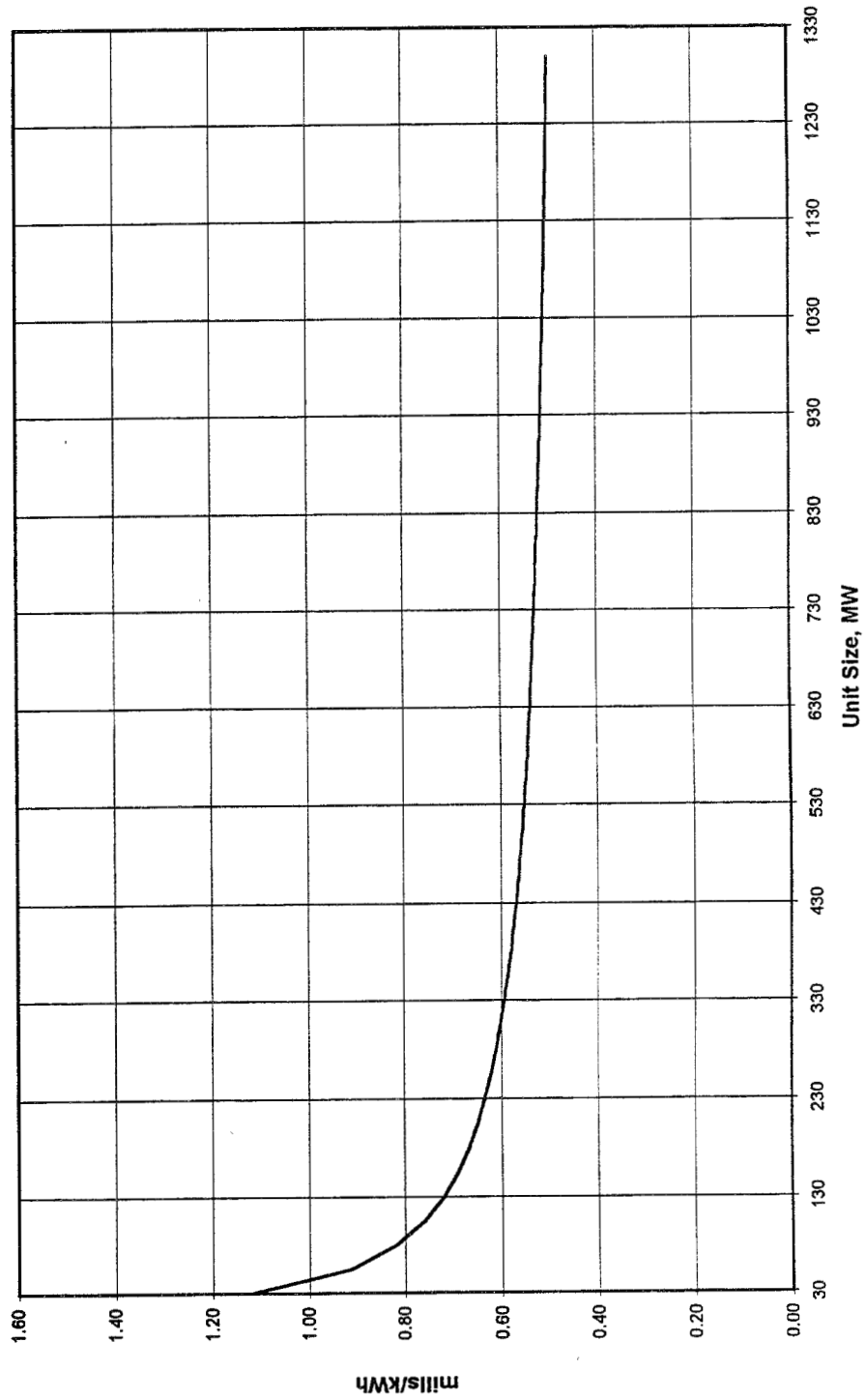
Figure 4-13
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
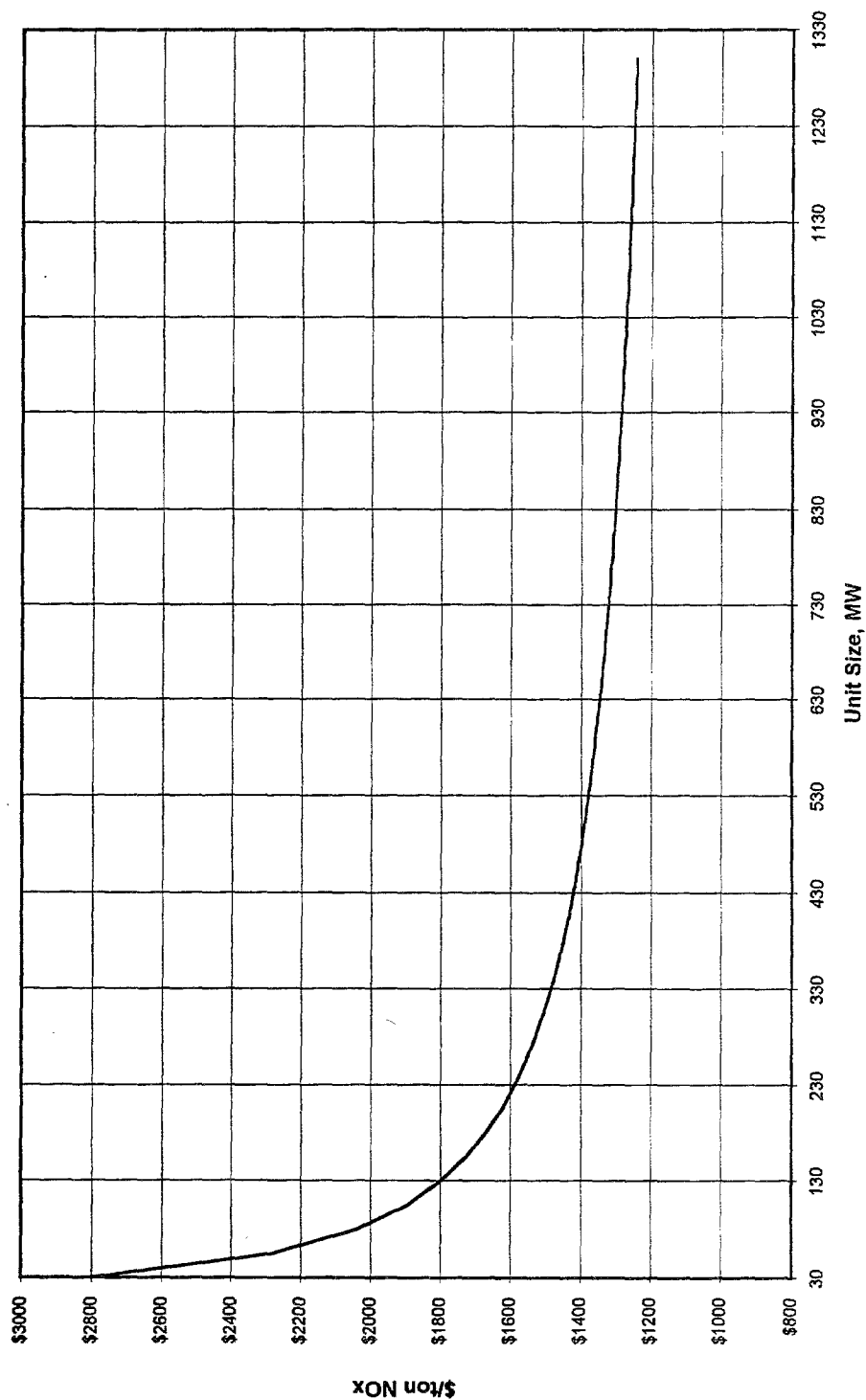
Figure 4-14

Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
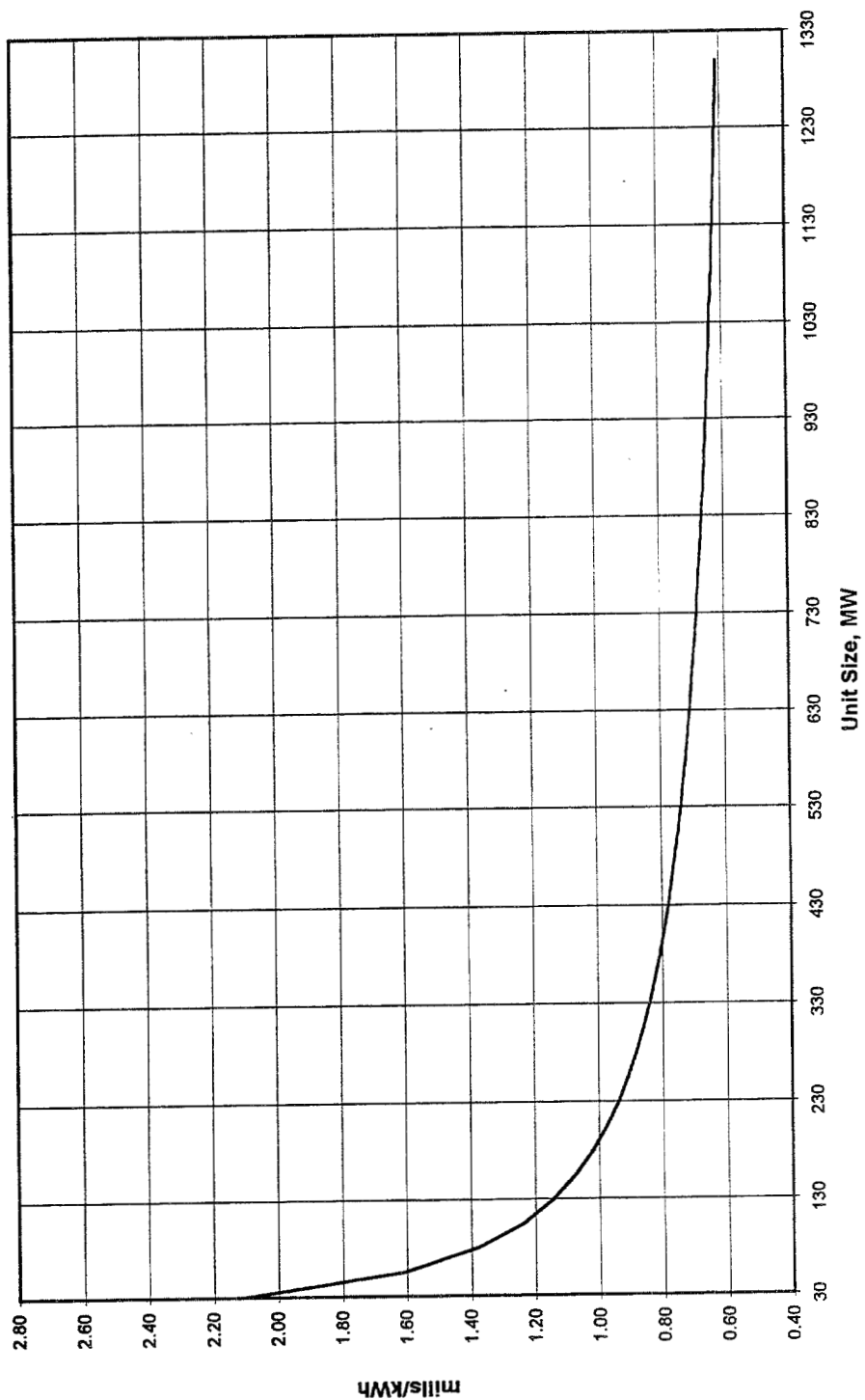
Figure 4-15
Gas-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
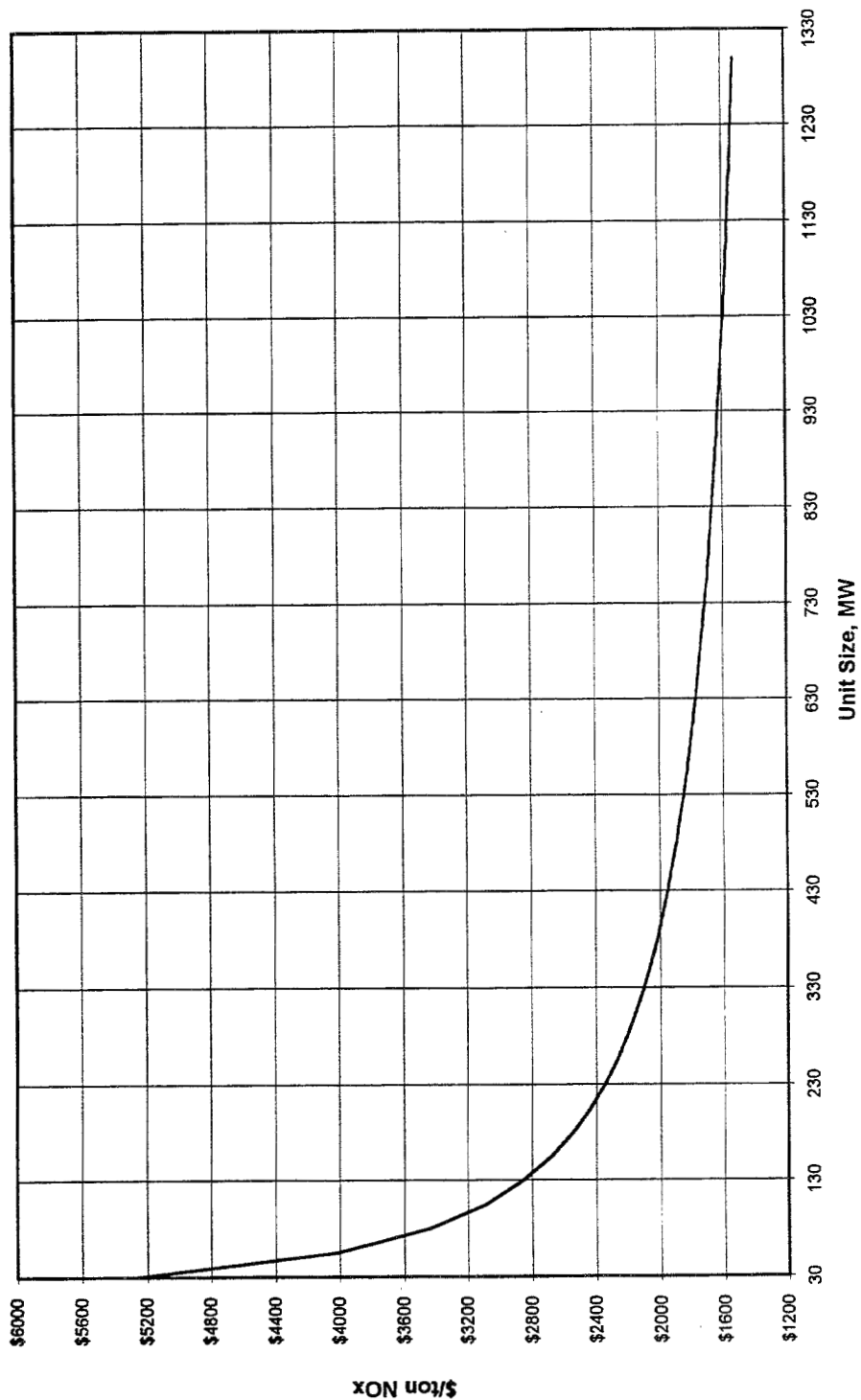
Figures 5-1 through 5-15

Figure 5-1
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
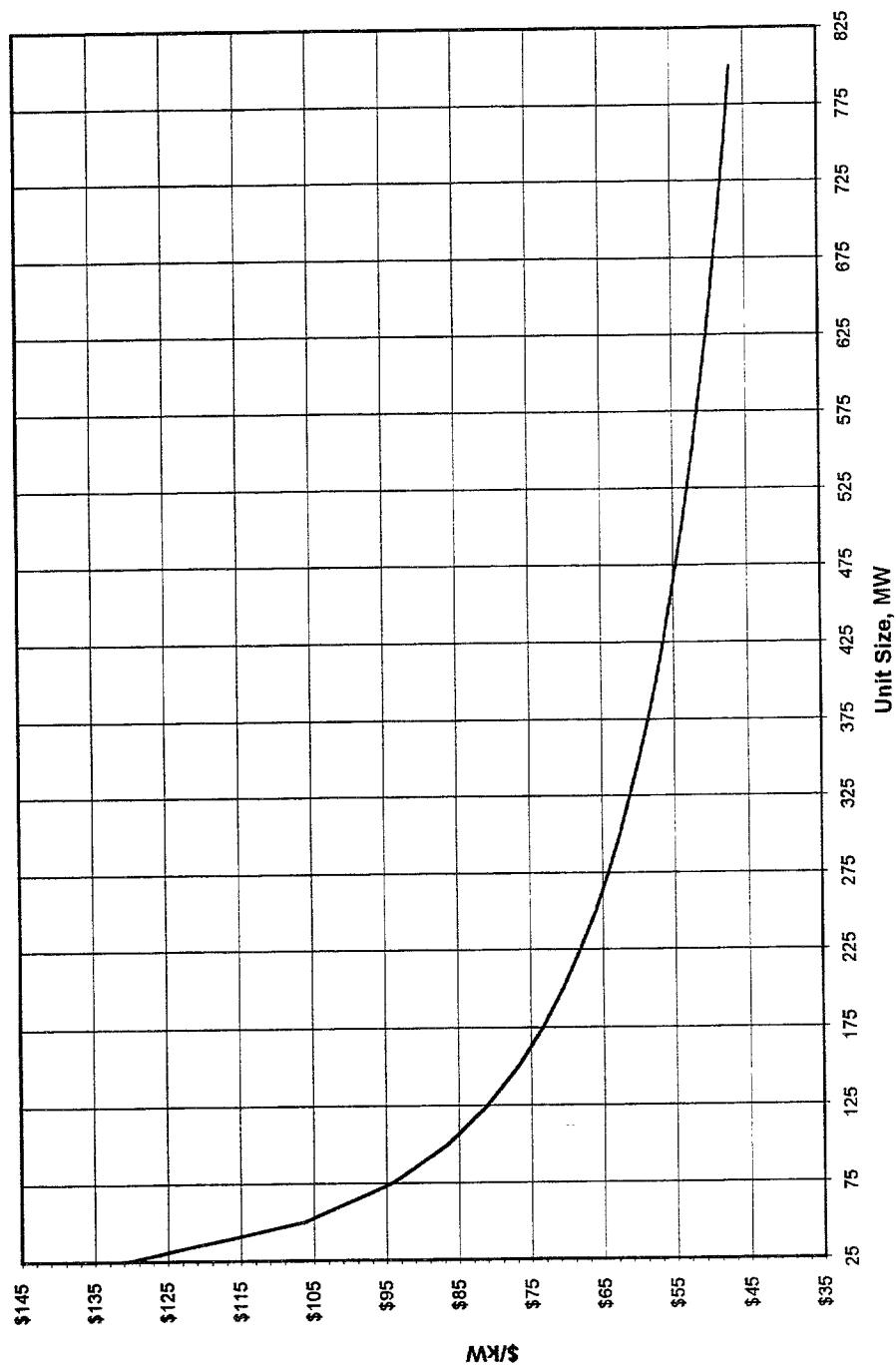**Base Capital Costs v. MW**
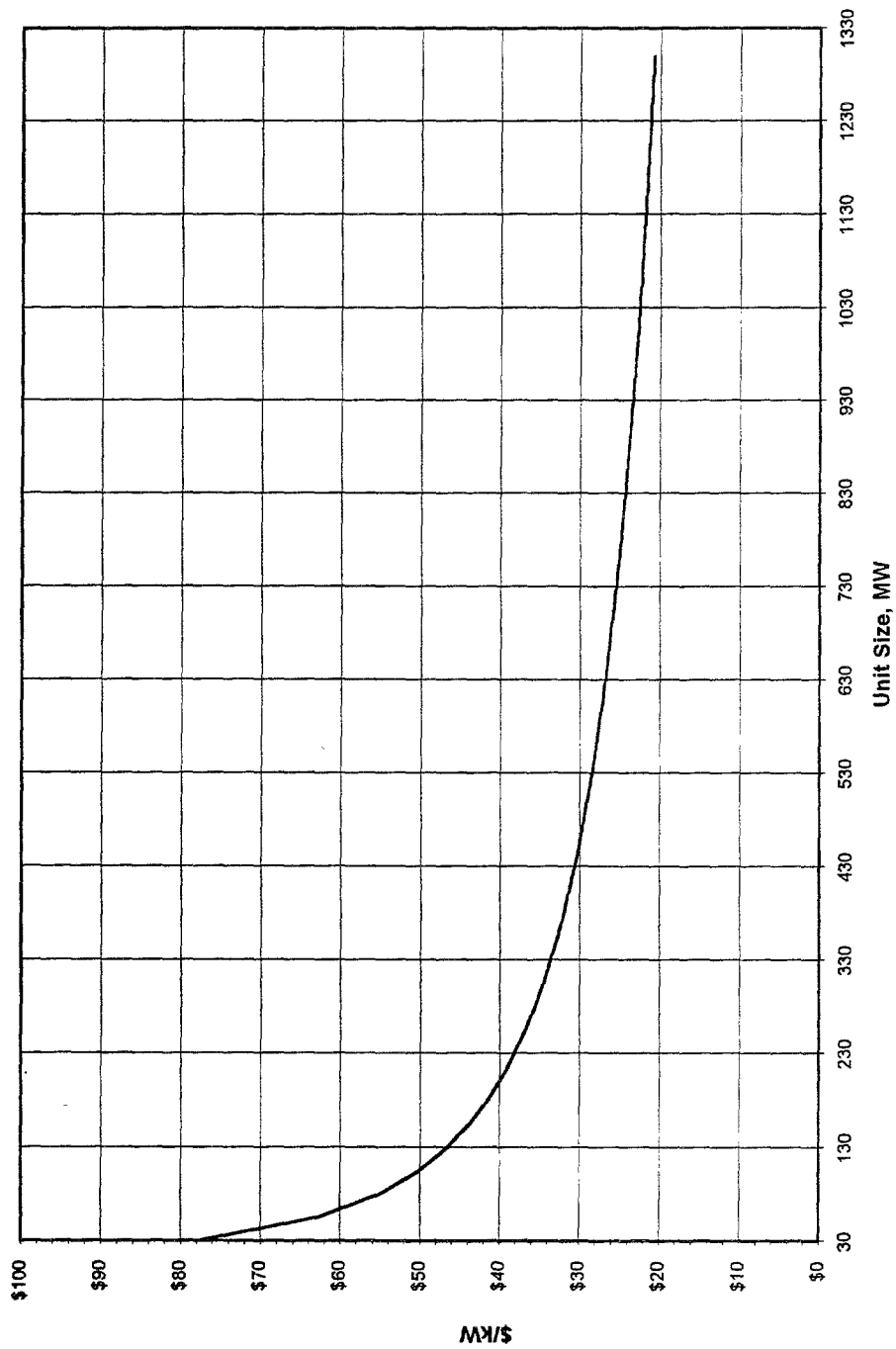
Figure 5-2
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
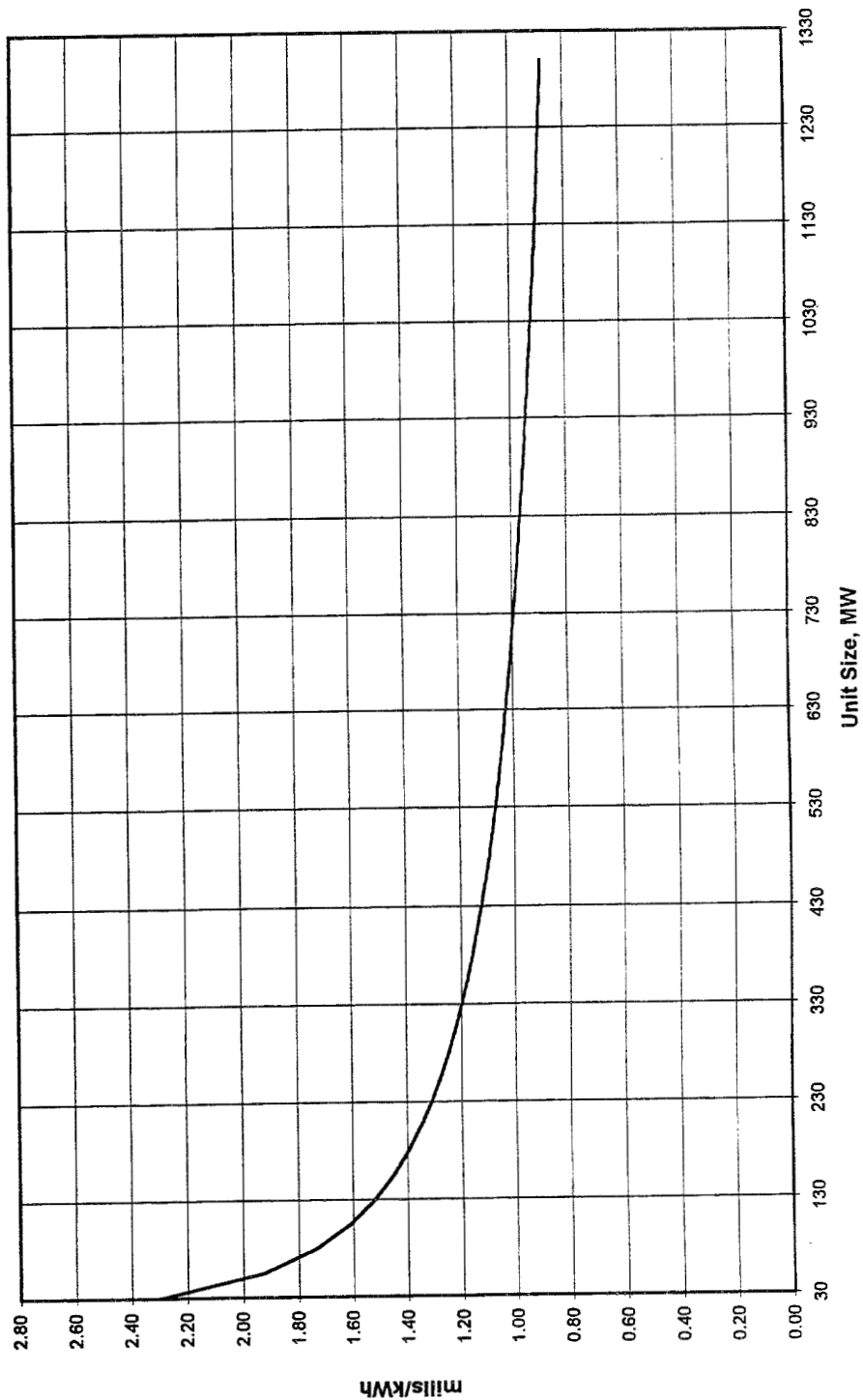
Figure 5-3
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
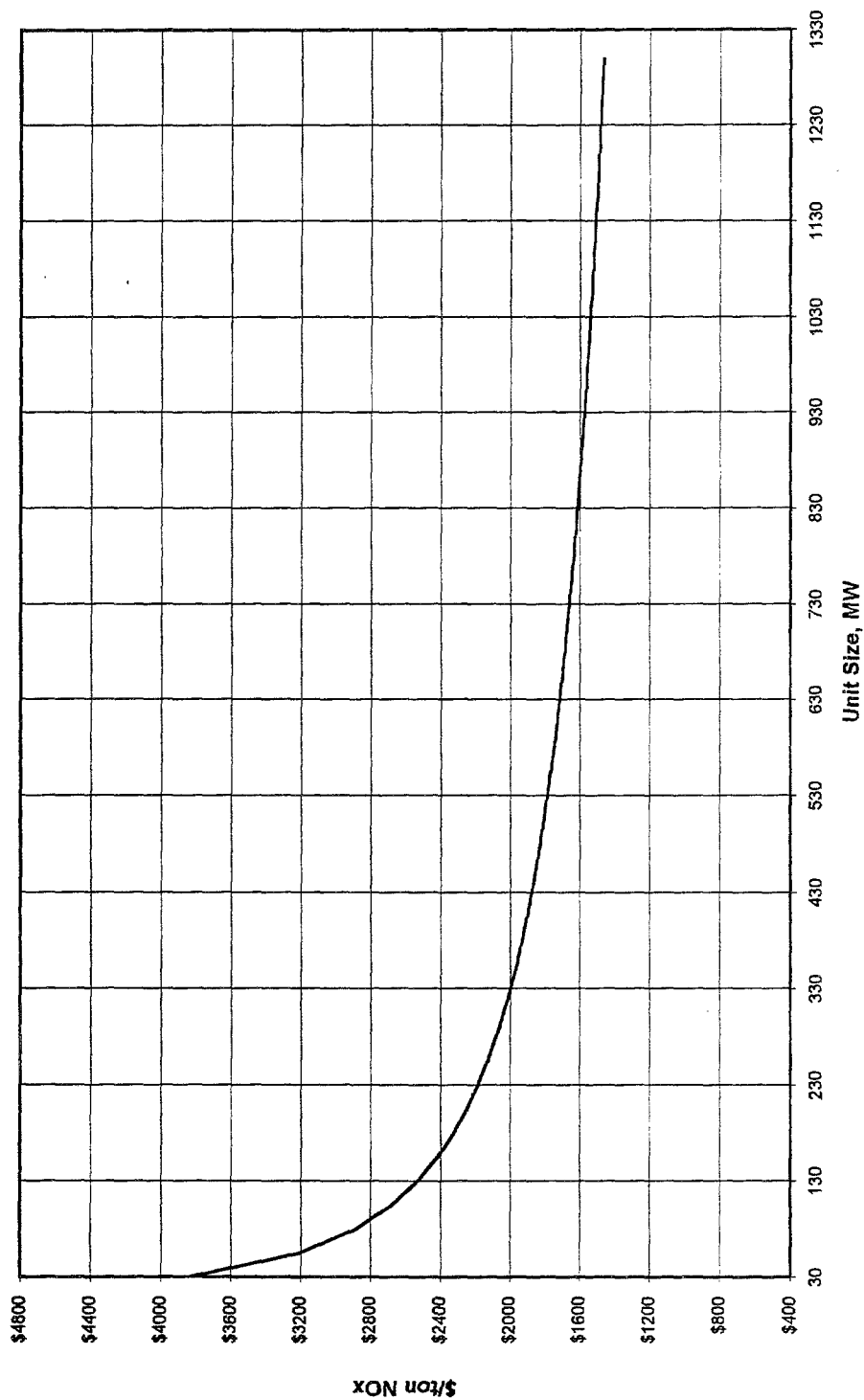
Figure 5-4
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case

Y-axis: mills/kWh
X-axis: Unit Size, MW
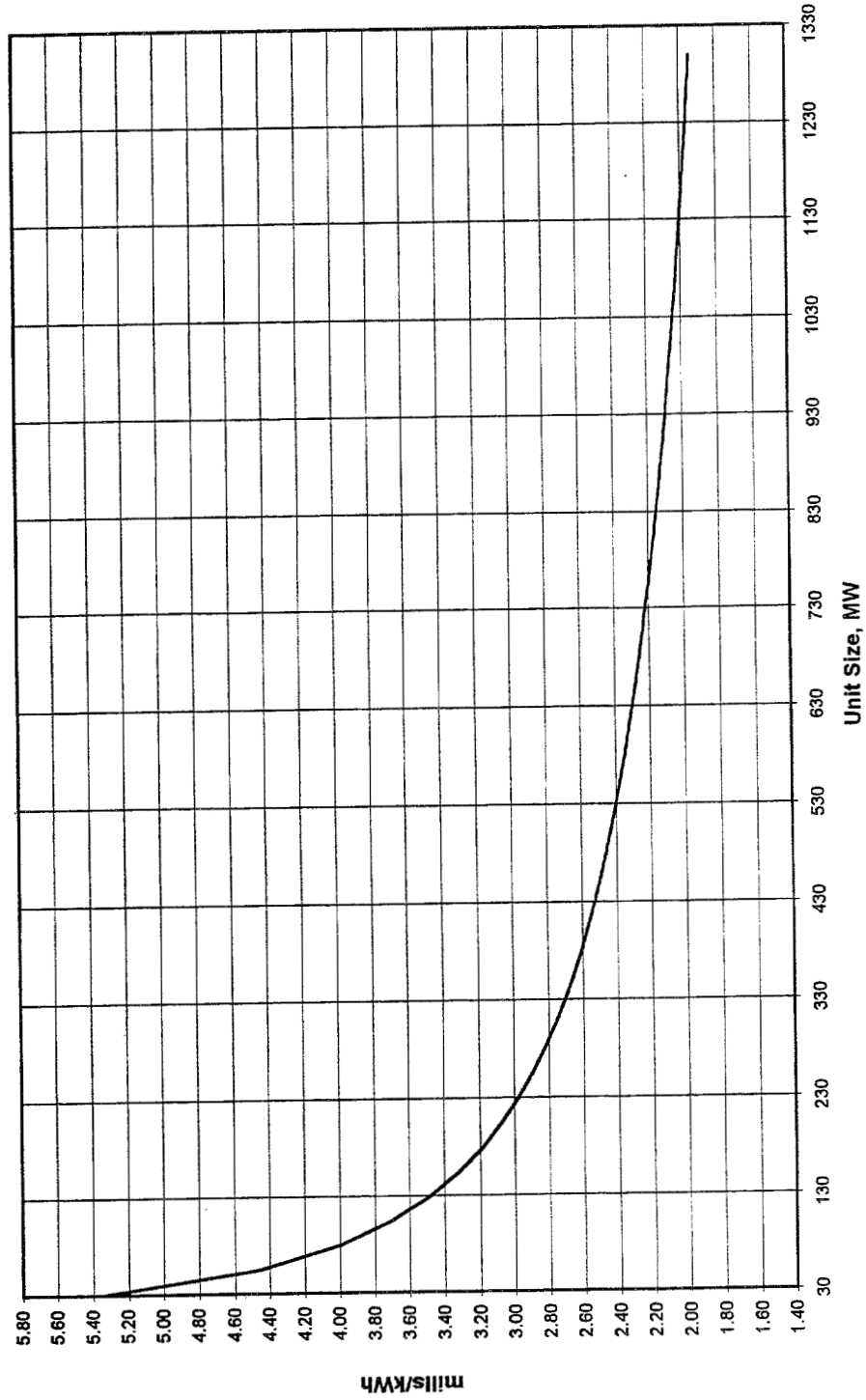
Figure 5-5
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
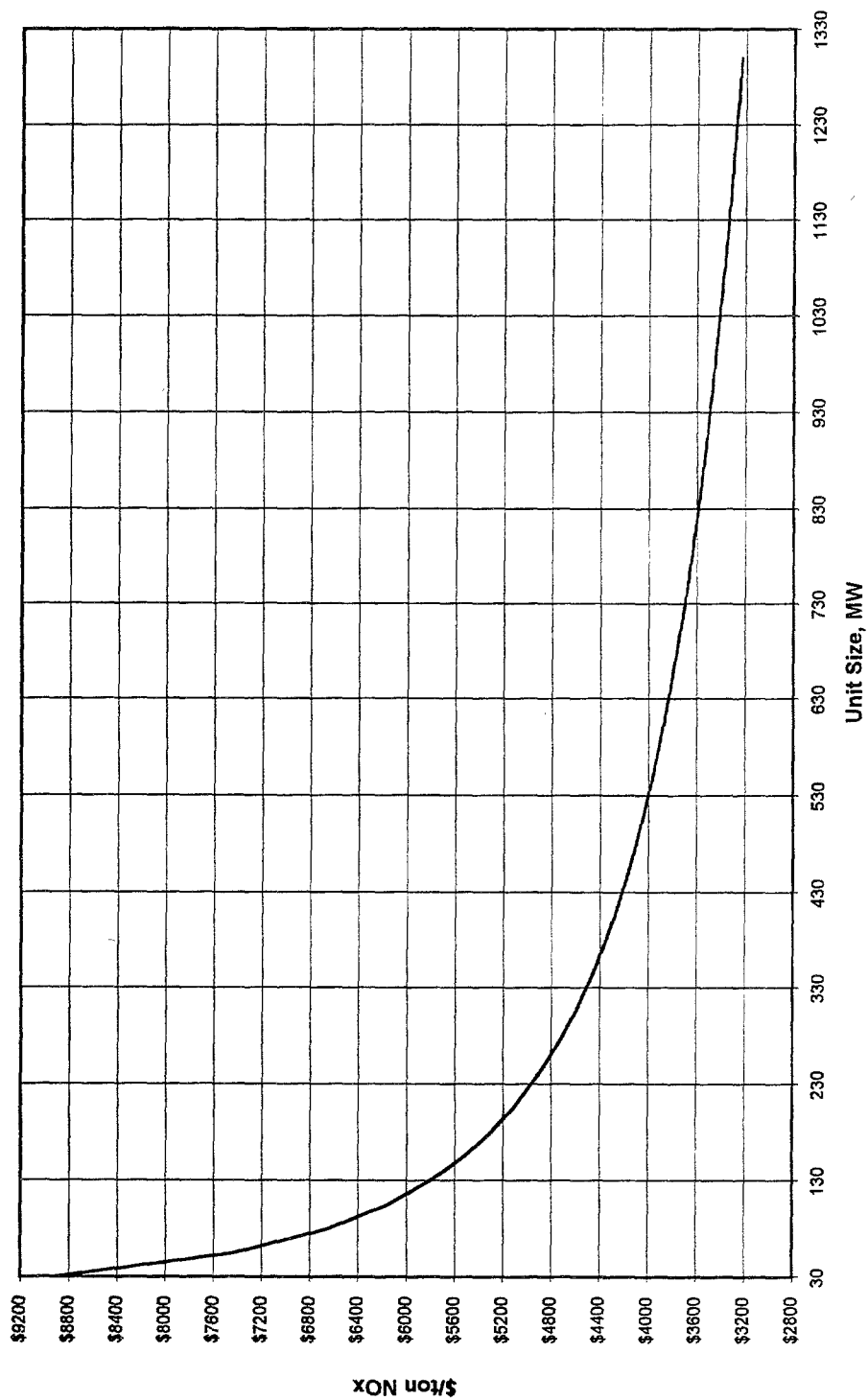
Figure 5-6
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Capital Costs v. MW
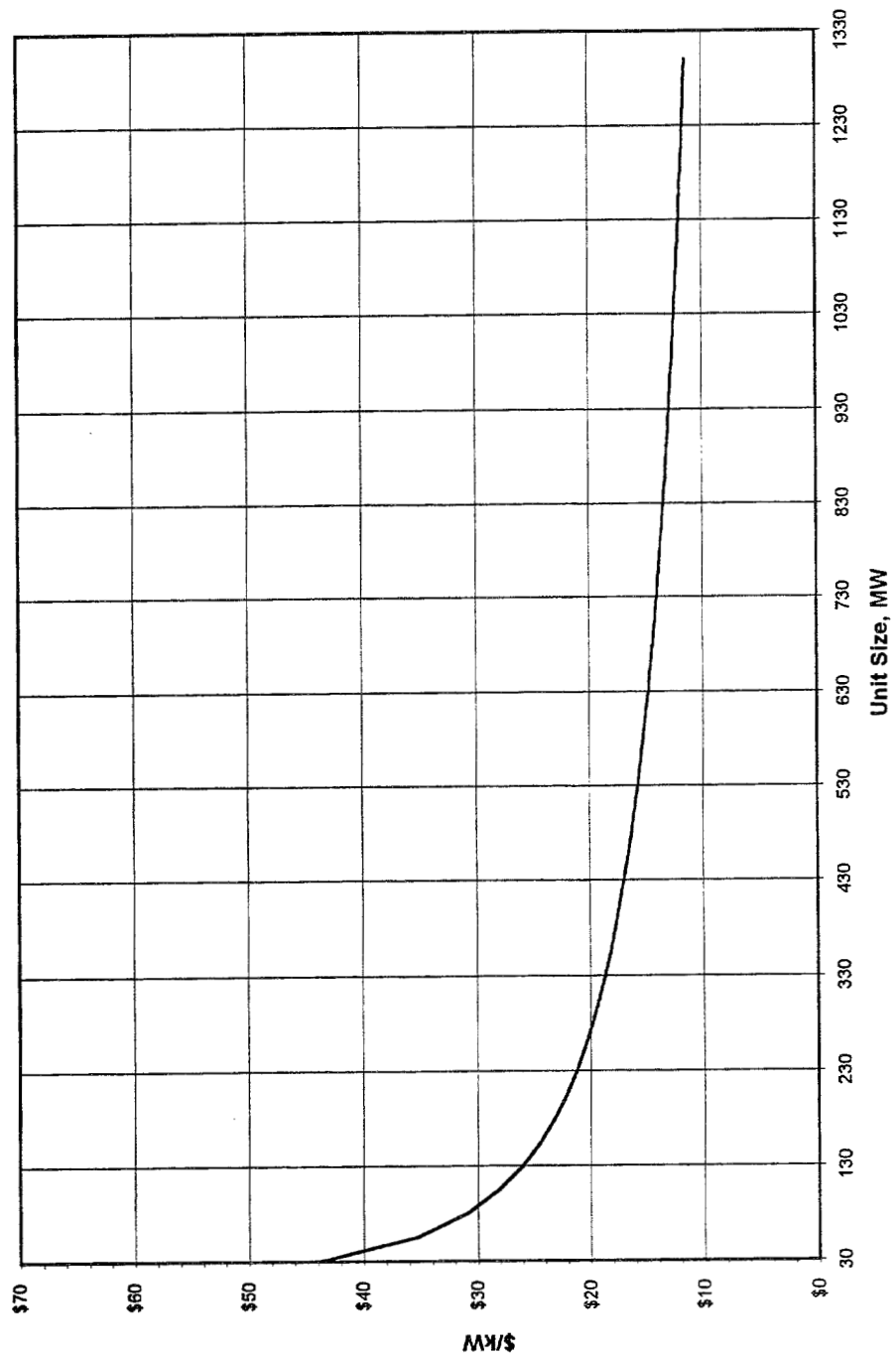
Figure 5-7
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
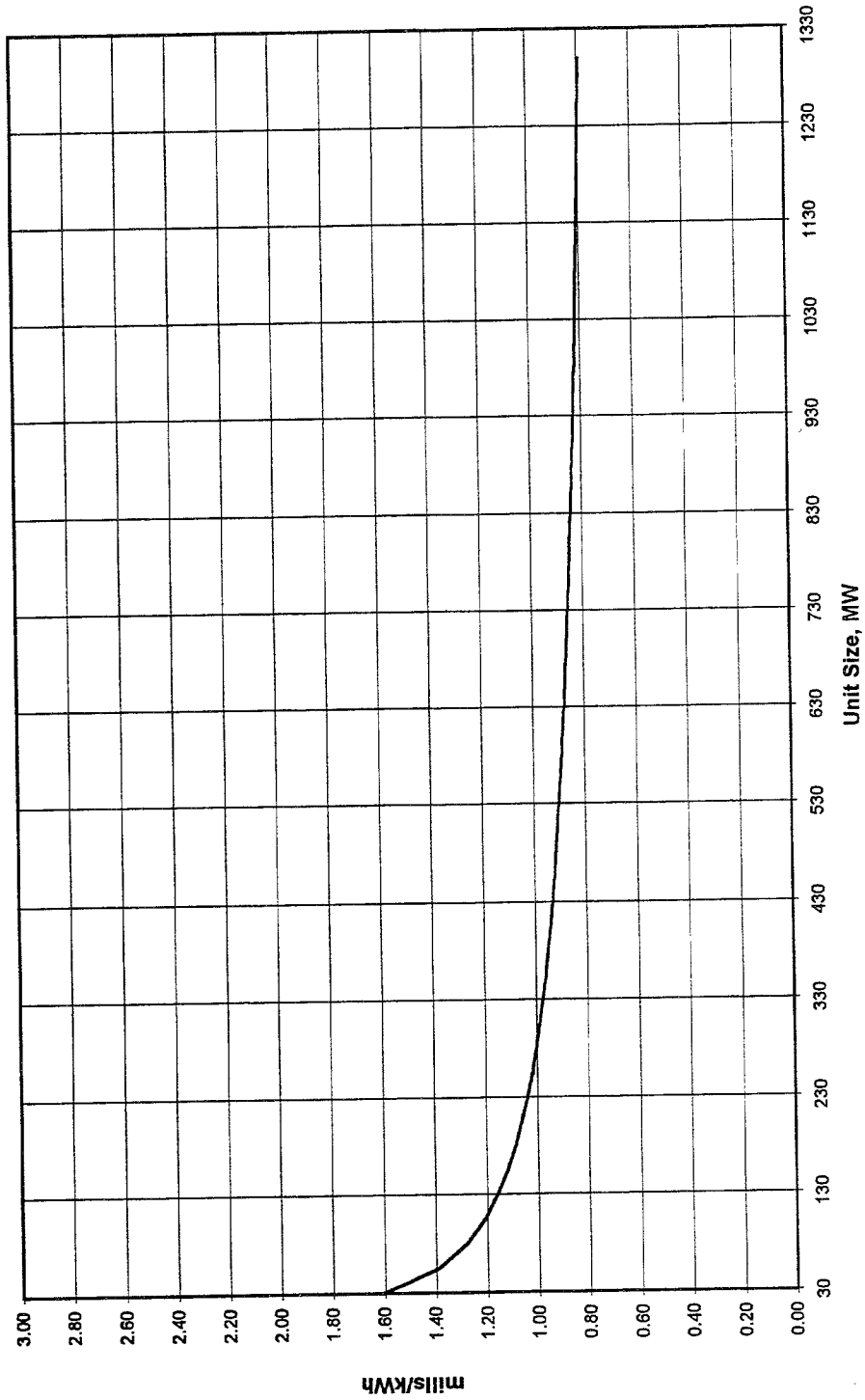
Figure 5-8

Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit

Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
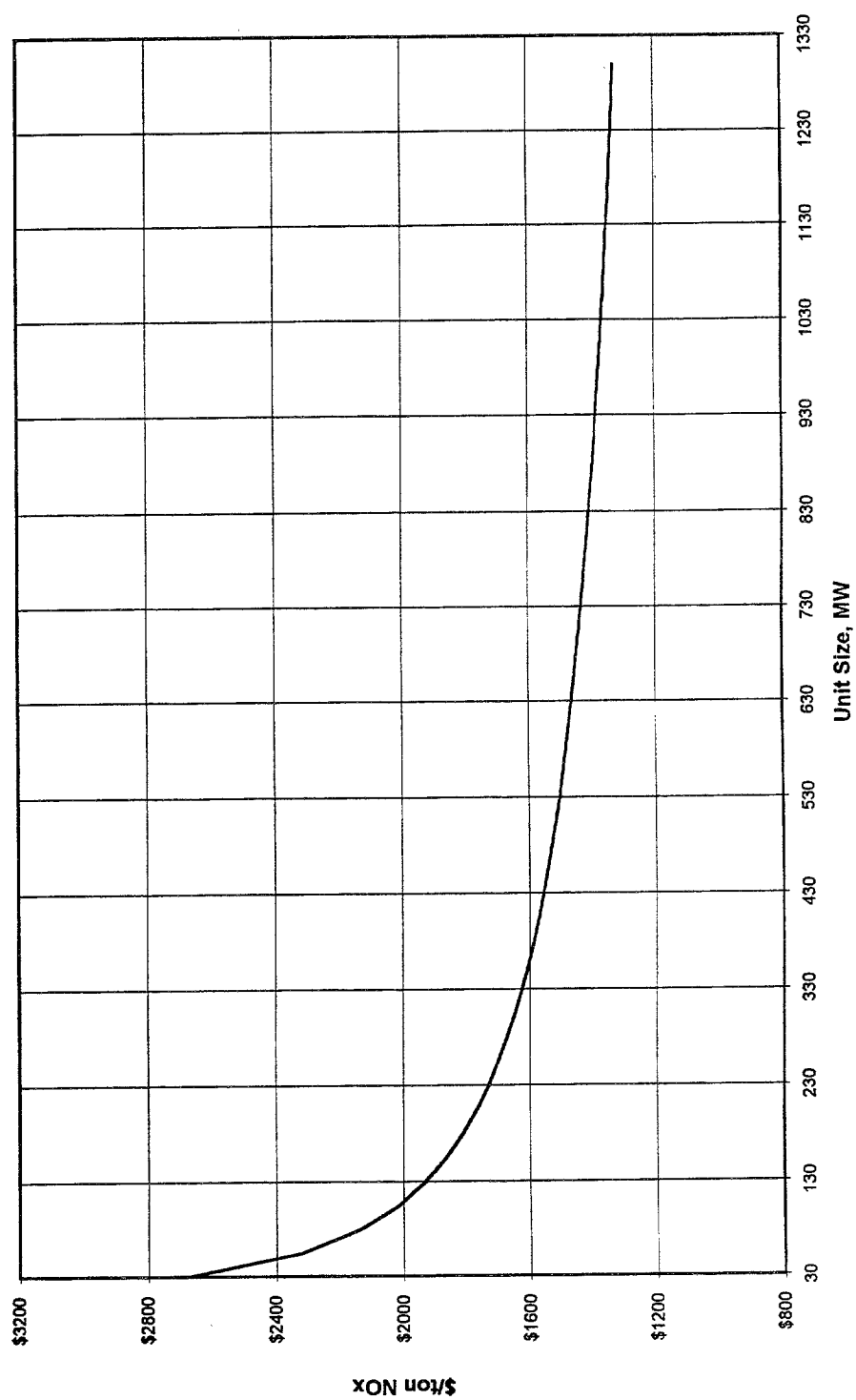
Figure 5-9
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
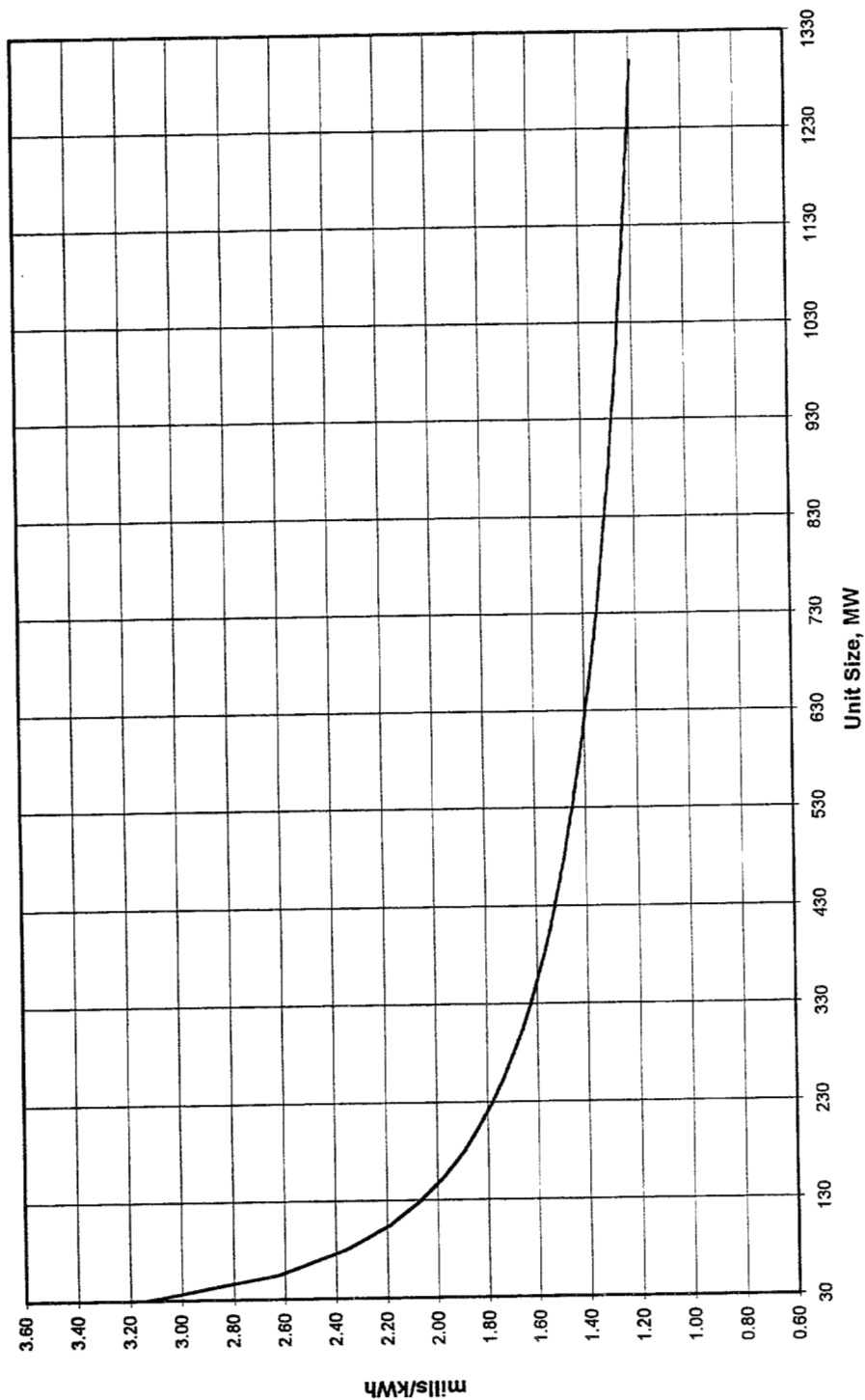
Figure 5-10
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu Gas Reburning Retrofit
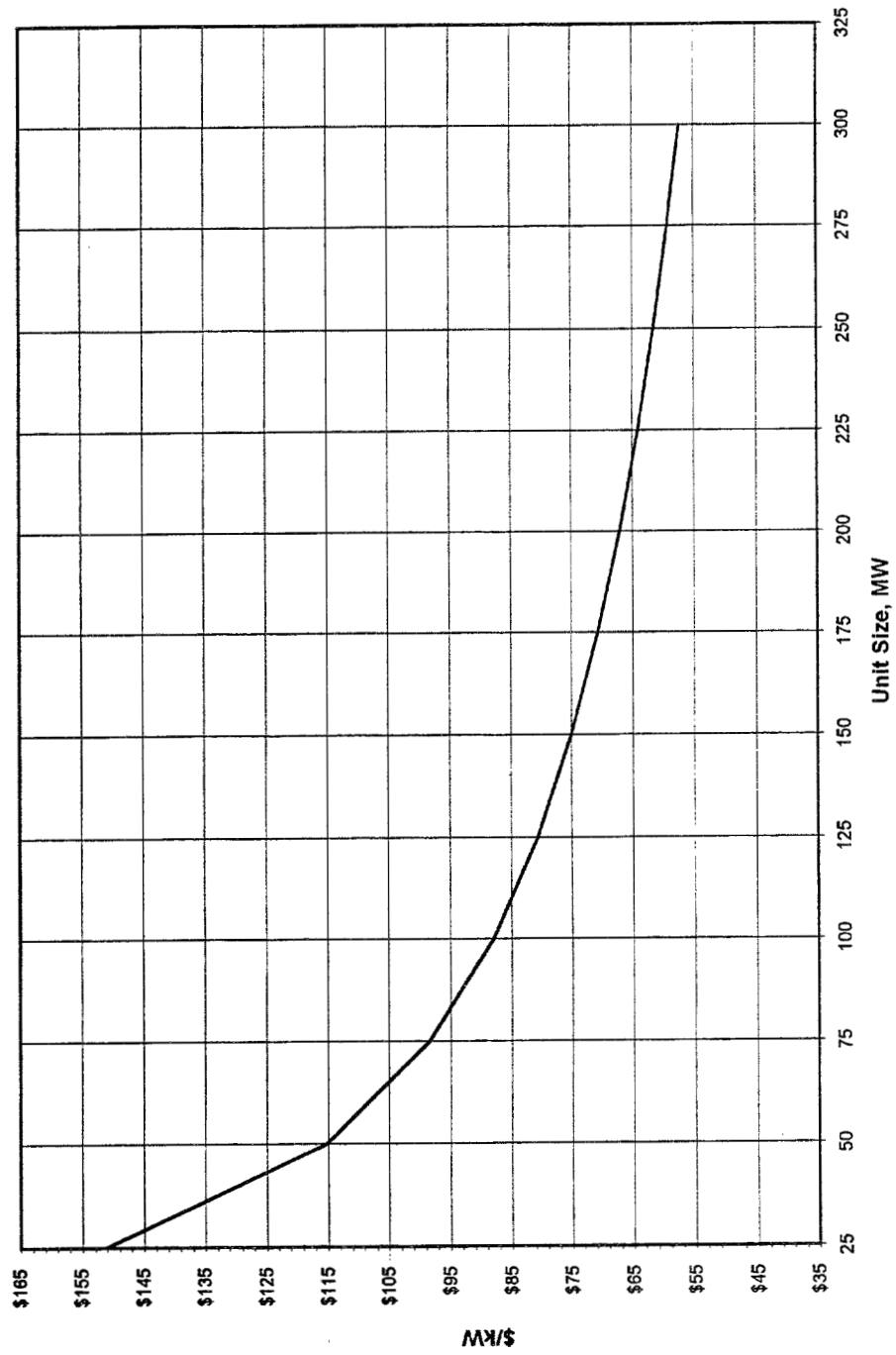Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
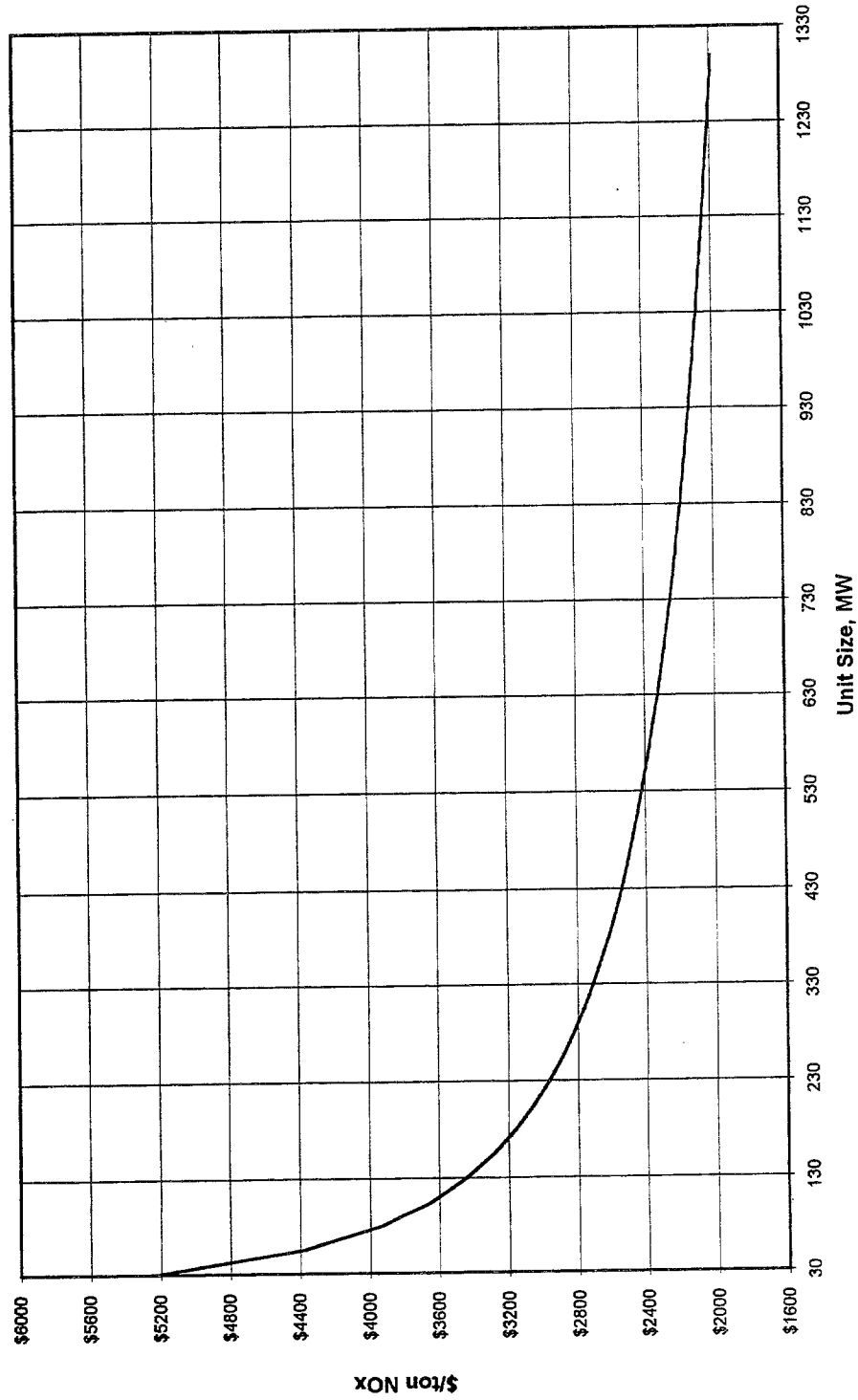
Figure 5-11
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Capital Costs v. MW
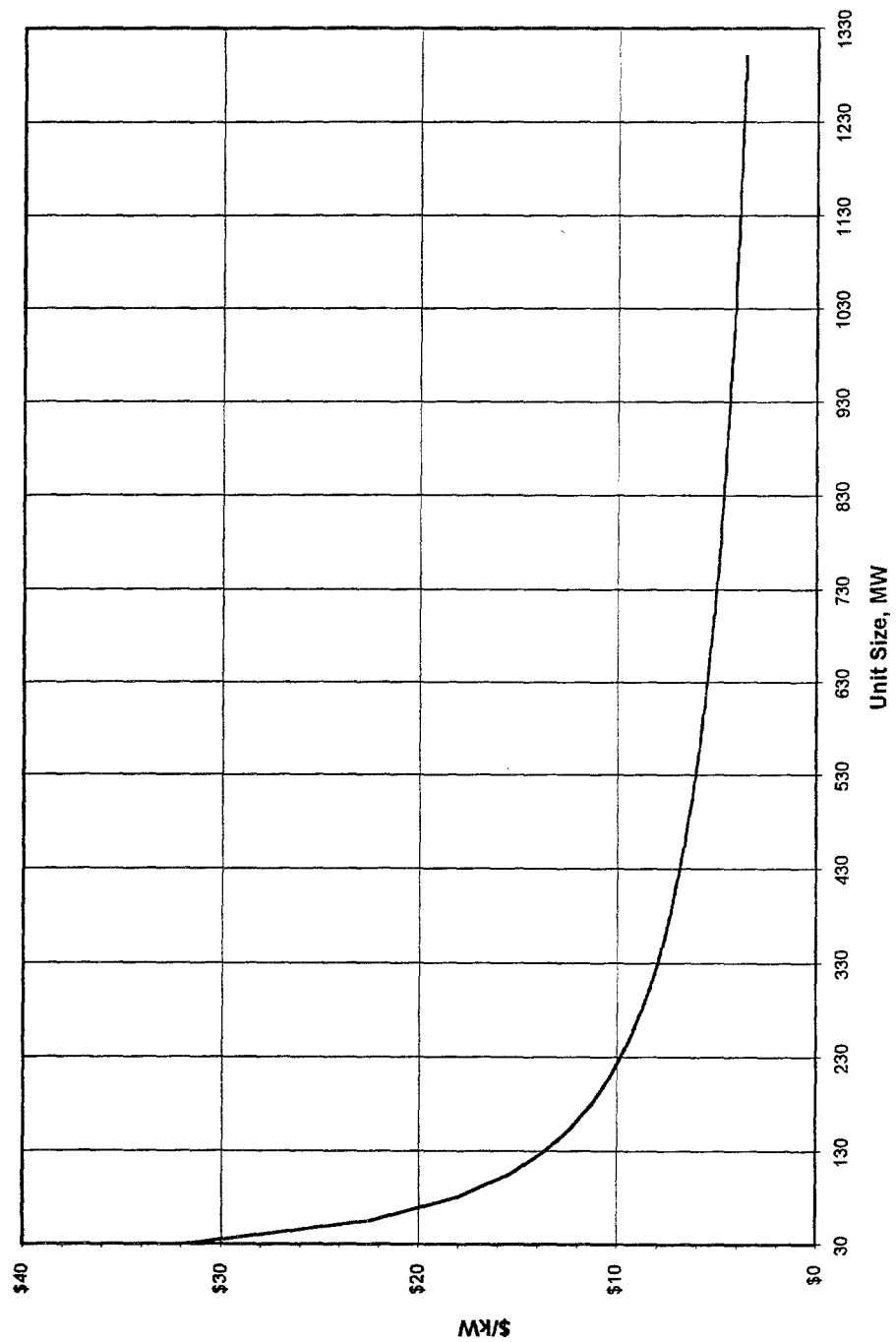
Figure 5-12
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 65% Capacity Factor Case
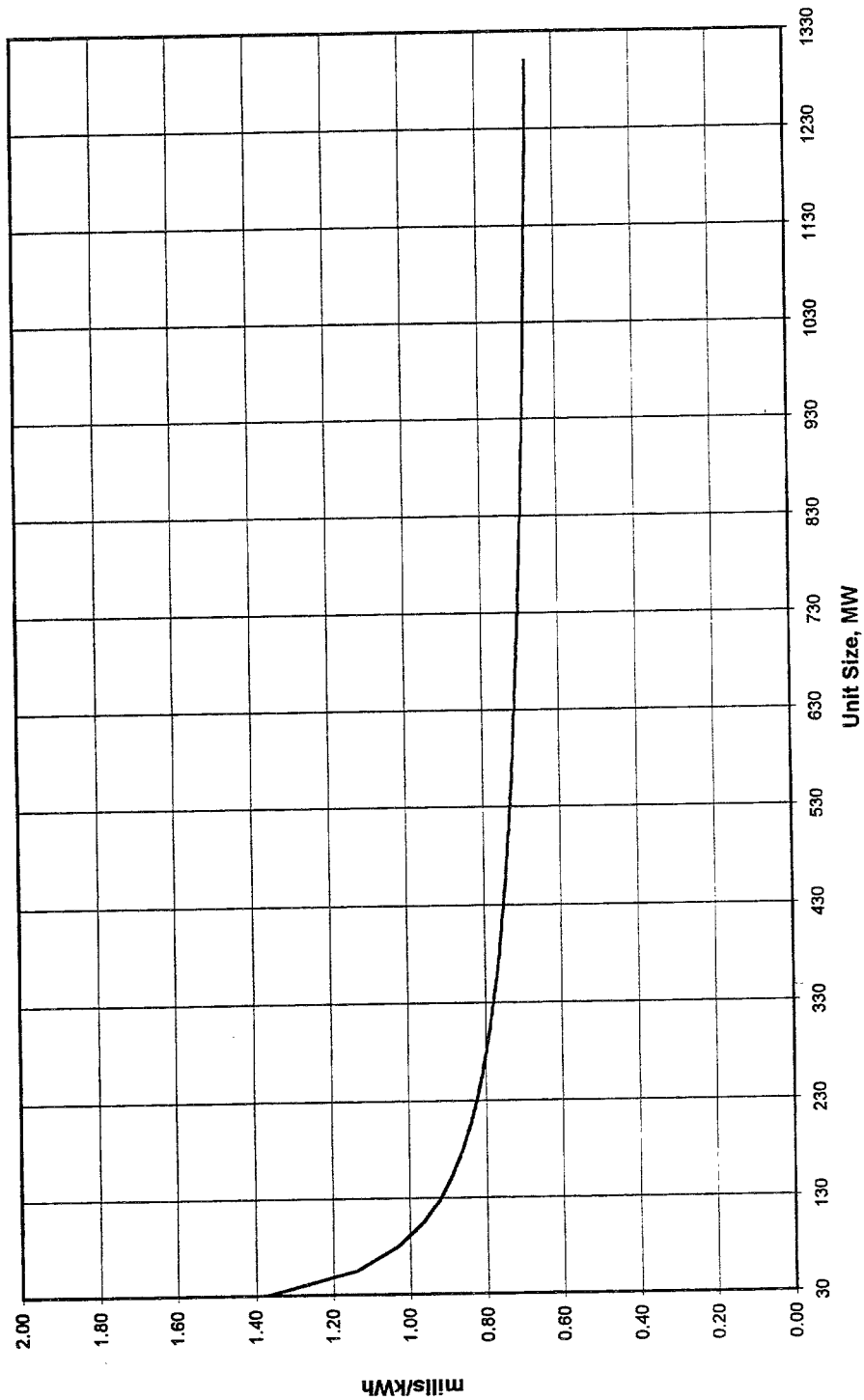
Figure 5-13
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 65% Capacity Factor Case
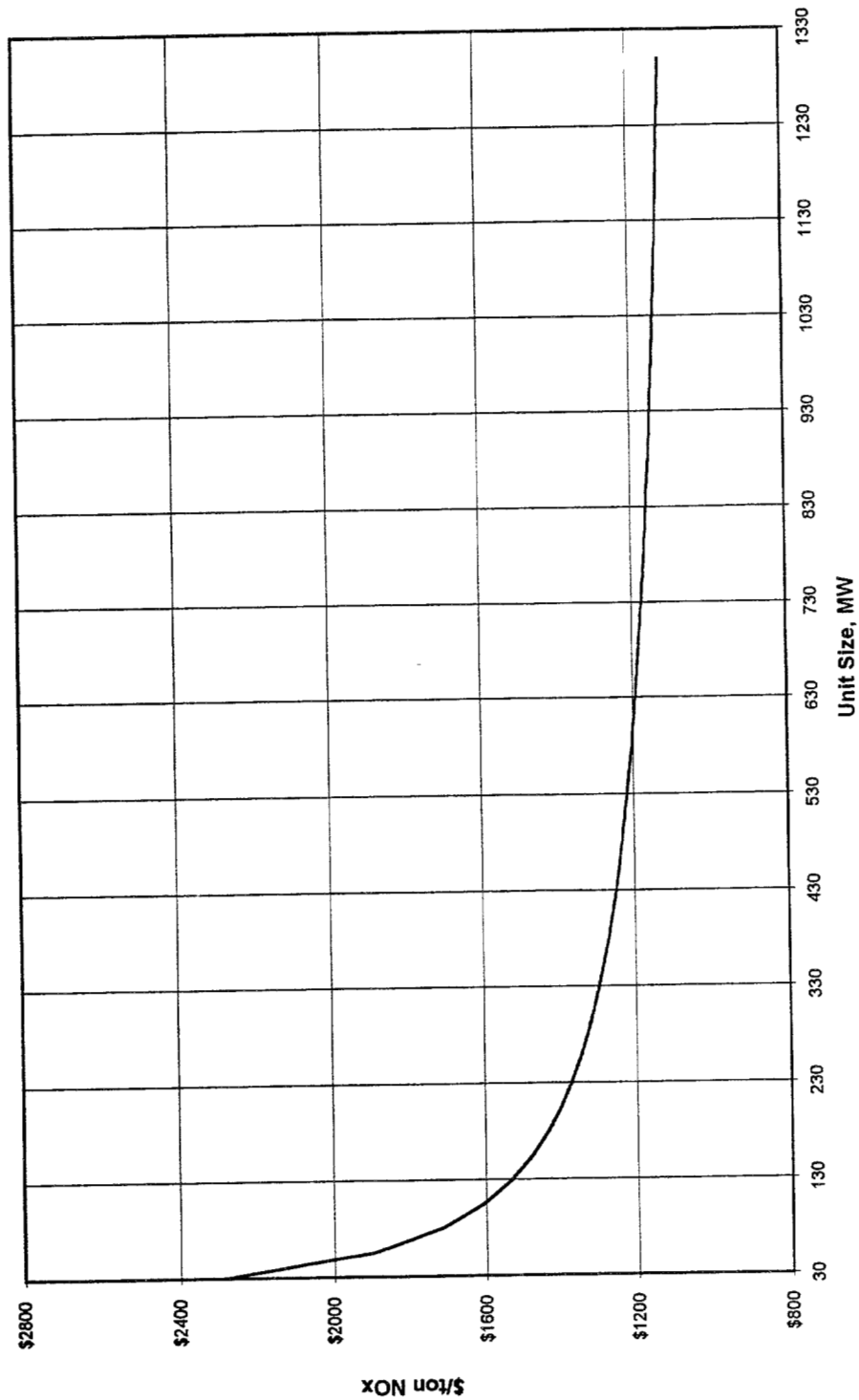
Figure 5-14
Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, mils/kWh v. MW - 27% Capacity Factor Case
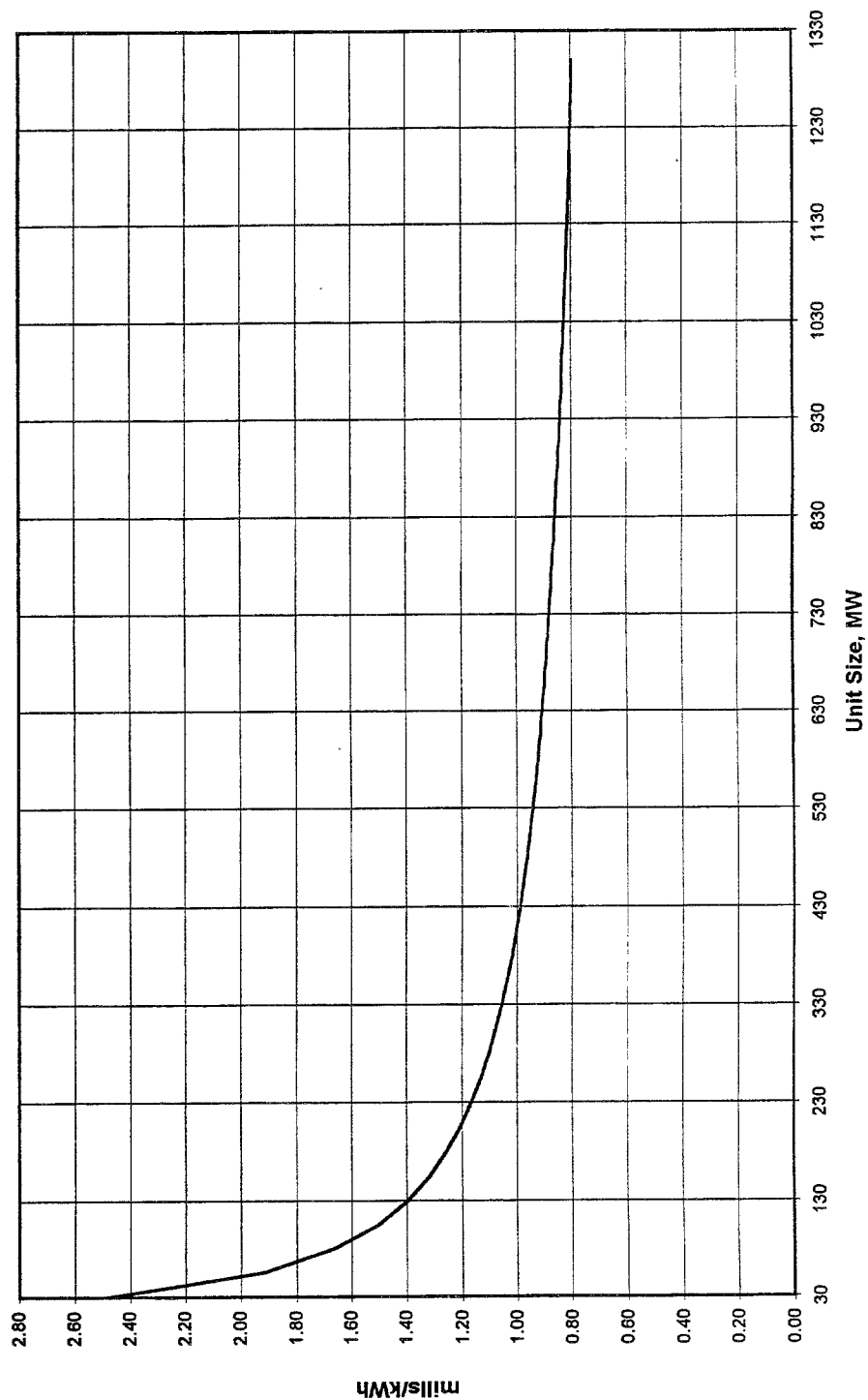
Figure 5-15
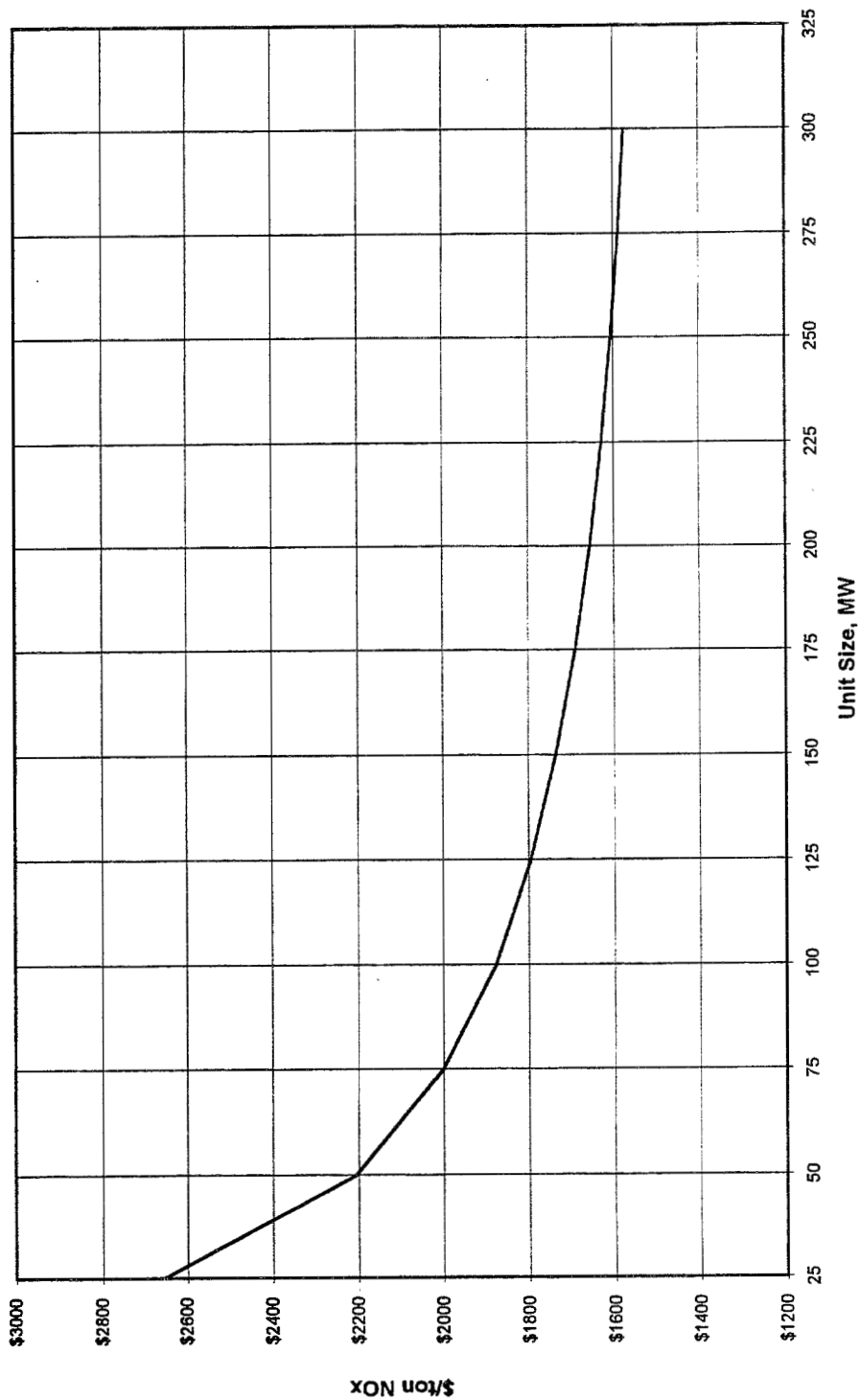Oil-Fired, Wall-Burner or Tangential Boiler, 0.15 Lb/MMBtu SNCR Retrofit
Base Levelized Costs, $/ton NOx removed v. MW - 27% Capacity Factor Case
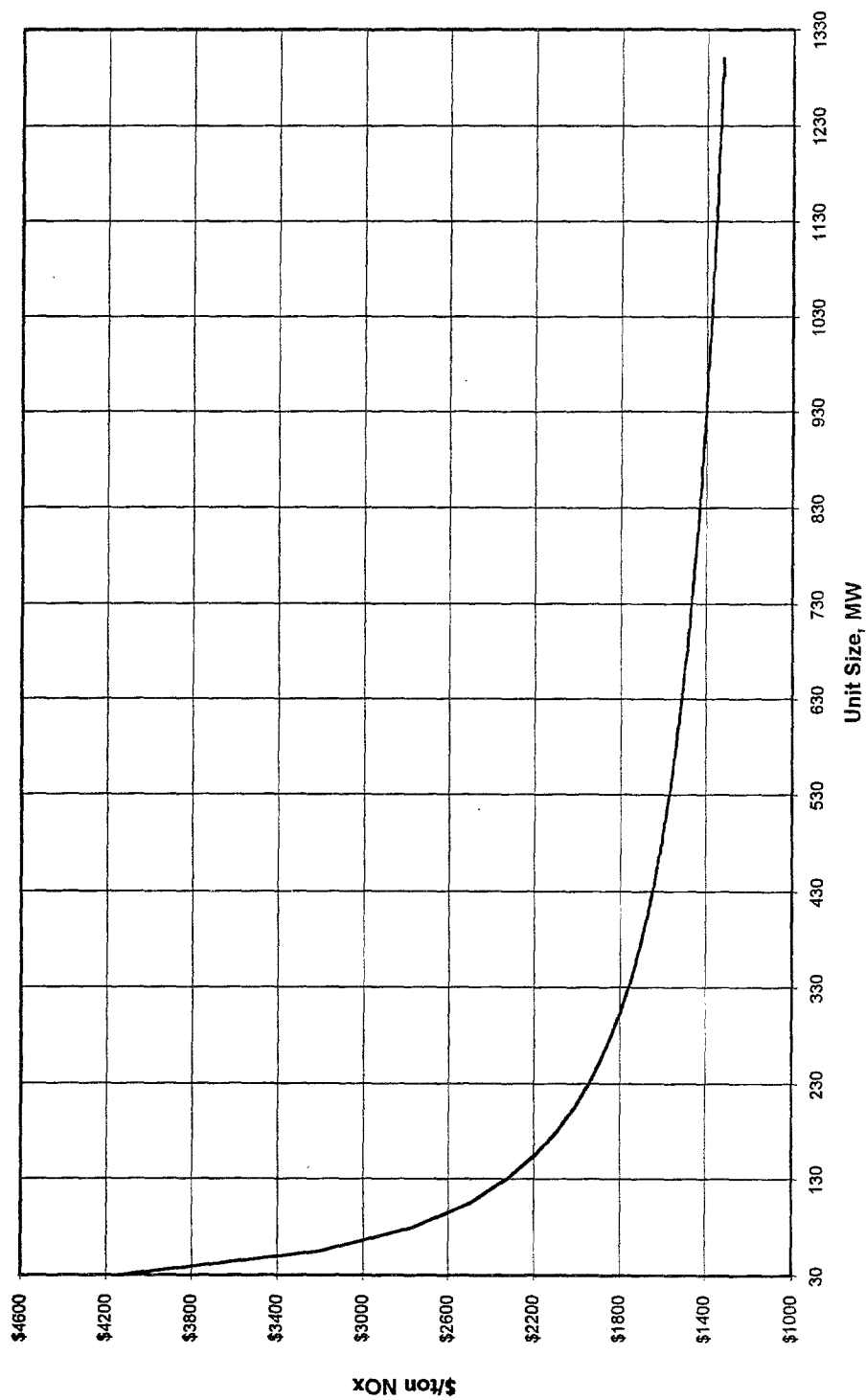
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RESPONSES TO COMMENTS ON THE MARCH 1996 DRAFT REPORT - COST ESTIMATES FOR SELECTED APPLICATIONS OF NO$_X$ CONTROL TECHNOLOGIES ON STATIONARY COMBUSTION BOILERS

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ATTACHMENTS

ATTACHMENT 1: CORROBORATION OF THE CAPITAL COST FOR MERRIMACK'S SCR INSTALLATION

ATTACHMENT 2: COPIES OF COMMENTS RECEIVED FROM PUBLIC

1.0 INTRODUCTION

The purpose of this report is to record responses to the public comments received on the EPA draft report, "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers." The Comments as well as corresponding responses are listed for each commenter separately. All of the appropriate editorial comments, although not listed below, will be incorporated in the next revision to the report. Copies of the correspondence containing these public comments are included as Attachment 2 in this report.

The report for another EPA study, "Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers," was attached as Appendix A to this draft report. The Group 2 boiler study was conducted in support of the Phase II NO_x control rule under Title IV of the 1990 Clean Air Act Amendment. Appendix A was included with this draft report as a reference, because the general technical and economic evaluation criteria and the design data for the typical Group 2 boilers described in Appendix A formed a basis for the evaluations in this report.

Some of the comments received on the draft report address items in Appendix A. Any Appendix A comments were addressed separately as part of the EPA's work on the Phase II rule. The discussion below, therefore, does not address any of the comments received on Appendix A.

The report in Appendix A was revised as a result of the public comments and reissued in August 1996. In the next revision to the study, the new, revised report will be included in Appendix A.

2.0 RESPONSE TO COMMENTS FROM DOE

The comments were provided in a May 20, 1996, letter from DOE to EPA. These comments along with the responses are provided below:

1. The report addresses both Groups 1 and 2 boilers. While Group 2 boilers are covered by Appendix A, no documentation is provided for Group 1 boilers.

    Response: Appendix A was attached to the report to provide a reference for the general economic evaluation approach for the study as well as to provide a reference for the design parameters of the Group 2 boilers used as the basis for cost estimates. While the general economic approach described in Appendix A applies equally to both Groups 1 and 2 boilers, the design parameters for Group 1 boilers have been covered in the report itself. Section 3.0 and Table 3-1 list design parameters for the tangential- and wall-fired boilers burning coal. Sections 4 and 5 and Table 4-1 include similar parameters for oil- and gas-fired boilers.

2. No background documentation is provided for the costs for achieving 0.15 lb/MMBtu of NO_x. Furthermore, no basis is given for the selection of the 0.15 lb/MMBtu target.

   Response: Section 2.0 of the report discusses in detail the basis for technology selection and economic evaluation criteria for achieving a NO_x emission rate of 0.15 lb/MMBtu. As mentioned in Section 2.3 of the report, the cost estimating methodology in most parts was the same as that used for a previous 1995 study conducted by EPA for estimating the costs of NO_x controls for the Group 2 boilers. The report for the 1995 study published in August 1995 was attached to the subject study as Appendix A.

   A controlled NO_x emission rate of 0.15 lb/MMBtu was selected as a reasonable level achievable with some of the commercially available NO_x control technologies. The capabilities of various NO_x control technologies are fully covered in Appendix A, which lists the experience to date with each of these technologies. Section 2.1 of the study describes as how the selection of the 0.15 lb/MMBtu NO_x limit was supported by this experience.

3. The statement in the first bullet item of Section 2.1 regarding low-NO_x burners (LNBs), overfire air (OFA) ports, and gas recirculation (GR) fans is not clear. If the combustion modifications are already in place for some boilers, are other technologies not technically or economically feasible?

   Response: The first bullet item of Section 2.1 is a summation of what is discussed in this paragraph prior to this item. As stated in the second paragraph of this section, the wall- and tangential-fired boilers being evaluated were assumed to be equipped with LNBs (one of the components of combustion controls). The first bullet item of this section is referring to the feasibility of applying other components (OFA and GR) of combustion controls to achieve the 0.15 lb/MMBtu limit on these boilers. As stated in this item, it is not technically feasible to achieve 40 to 70 percent of NO_x reduction by adding OFA and/or GR to the boilers already equipped with LNBs.

4. Inclusion of overfire air ports with low-NO_x burners has been disallowed in the past NO_x control rules. Should it be considered now?

   Response: The purpose of the study was to consider all of the commercially available NO_x control technologies for NO_x emission limits being considered for future rules. Consideration of OFA is important and justified because it is a relatively low capital-cost approach that can provide a substantial NO_x reduction.

5. The report appears to be biased in favor of SNCR. Technologies other than those evaluated in the study could also be used. There is insufficient

discussion in the study to inform the readers of reasons for the study conclusions.

Response: The evaluation of NO_x control technologies considered in the study has been based strictly on the technology merits and capabilities. One of the conclusions in the study was that SNCR is not a viable technology for achieving the 0.15 lb/MMBtu NO_x emission limit on coal-fired boilers (this cannot be termed as a favorable conclusion). It was, however, concluded that SNCR could be applied to gas- and oil-fired boilers with proper requisites, such as adequate residence time in the flue gas temperature zone to support the reaction between the reagent and NO_x.

SNCR was also evaluated for coal-fired boilers based on its ability to provide substantial NO_x reduction. As clearly stated in the study, application of SNCR would depend on site-specific factors, one being the presence of the aforementioned residence time (refer to Section 2.1).

The study has evaluated all of the available commercial technologies that could be considered for achieving the 0.15 lb/MMBtu emission limit (refer to Section 2.0). The merits of these technologies have been covered in detail in Appendix A of the study. The study does mention the possibility of utilizing a combination of technologies to achieve the 0.15 lb/MMBtu limit, such as a hybrid system using both SCR and SNCR or a system using SCR in conjunction with portions of combustion controls (refer to Section 2.1). These systems are, however, considered an optimization of individual technologies, and they were not evaluated because of the limited scope of the study.

The study draws from the extensive work done concerning the technical and economic evaluation of NO_x controls in the aforementioned Group 2 boiler report. The Group 2 boiler report was attached to the study report as Appendix A specifically to provide the readers with the background information on the approach and methodology used in the study.

6. The levelized costs are reported (Table 1-2) both with and without the capital charge component. The levelized costs should only be reported with the capital charge.

Response: The total levelized costs, including the capital charge, for each technology application are presented in Tables 1-3 and 1-4 as well as in Figures 3-1 through 3-40, Figures 4-1 through 4-15, and Figure 5-1 through 5-15. Additional information in Table 1-2 was specifically included to differentiate between various technology applications based on the contribution of the capital and operating costs to the total levelized costs. This information is useful in that it readily identifies the technologies that

are capital cost intensive as well as those that are operating cost intensive. Therefore, we recommend keeping the information in Table 1-3 unchanged.

7. There is no supporting documentation for some of the cost estimates presented in Tables 1-2 through 1-4.

   Response: It is not clear what additional supporting documentation, other than that provided in the study, is required. The evaluation criteria, assumptions, and economic factors are detailed in Sections 2.0 through 5.0 and Table 2-1. The overall cost estimating approach is presented in Appendix A, which also lists the boiler design parameters for coal-fired, cell-burner, cyclone, wet bottom, and vertically fired boilers.

   The design parameters for wall- and tangential-fired boilers burning coal, gas, and oil are presented in Tables 3-1 and 4-1. In addition, the consumables associated with each technology application are presented in the various sections of the study. All of the cost estimates presented in the study can be verified by using the information on consumables and the economic parameters presented in Table 2-1.

8. The cost figures presented in the study are not consistent. For example, Table 1-3 shows a levelized cost of $695/ton for SCR applied to a 200 MW cyclone boiler at a 65 percent capacity factor. Figure 4-21 in Appendix A shows a value of about $625/ton for the same boiler at the same capacity factor.

   Response: Appendix A was attached to the study report to provide the reader information on the evaluation criteria, technical background on each technology, and design information on certain coal-fired boilers used in the cost estimates for the study. The design basis for the NO_x control technologies in Appendix A was different from that used in this study. For example, the SCR system in Figure 4-21 of Appendix A was designed for a NO_x removal rate of 50 percent. In comparison, the cyclone-fired SCR cost presented in Table 1-3 of the study is based on a NO_x reduction rate of approximately 87 percent.

   The design basis for each technology application is clearly stated in both the study and Appendix A. The costs are, therefore, not comparable when a difference exists between the two design bases.

9. On Page 1-2 of the study, a reference to economic factors "reported" in the EPRI TAG has been provided. Since the economic factors in the EPRI TAG are only examples and are not meant to be recommendations, the word "reported" should be replaced with the term "listed" or "given".

   Response: The recommended change will be incorporated in the report.

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10. The basis for the two capacity factors (27 and 65 percent) mentioned in Section 1.3 of the report should be explained in greater detail for the levelized costs in mill/kWh reported in Table 1-2.

   Response: The notes provided at the bottom of Tables 1-2 through 1-4 will be expanded to further explain the basis for the capacity factors.

11. Revise Table 1-1 to identify Group 1 and 2 boilers separately.

   Response: The recommended change will be incorporated.

3.0 RESPONSE TO COMMENTS FROM ICAC

The comments were provided in a May 28, 1996, letter from ICAC to EPA. The comments along with the responses are provided below:

1. The report should note that cost effectiveness value (expressed in $/ton of NO_x removed) will decrease as capacity factor increase over 65 percent.

   Response: A typical capacity factor of 65 percent was selected for the power plants in general. It is recognized that there will be plants operating above and below the 65 percent factor. A note will be added to reflect that cost effectiveness values can vary with the capacity factor, i.e., increasing when the capacity factor decreases and decreasing when the capacity factor increases above the 65 percent value.

2. The report should include calculated SNCR costs for all boiler/fuel combinations. While SNCR alone may not be sufficient to reduce NO_x emissions to 0.15 lb/MMBtu in all cases, SNCR may be part of the combinations of control technologies.

   Response: SNCR has been evaluated for all of the Group 1 boilers considered for the study. Further, Appendix A evaluates SNCR application on cyclone, vertically fired, and wet-bottom boilers. For these boilers with relatively low baseline NO_x emissions, SNCR can reduce NO_x to significantly low levels. Viability of using SNCR along with another technology (as a hybrid system) for Group 1 and 2 boilers was recognized in the report (refer to Section 1.4). Because of the limited nature of the study, evaluation of such hybrid systems was considered outside of the scope.

3. The report overestimates initial catalyst charges and catalyst replacement rates for SCR, and thus overestimates SCR costs. Actual original installed catalyst volumes (cubic meters of catalyst per MW of plant capacity) are 20 to 75 percent lower than the volumes used in the report. Improvements in

catalyst technology and experience over time have allowed installation of smaller catalyst volumes.

The report also conservatively assumes total replacement of the catalyst bed every 3 years for coal-fired boilers. This assumption inflates actual catalyst replacement costs by a factor of 1.3 to 3, depending on the boiler type, and therefore introduces unacceptable errors into the cost calculations. Industry experience universally supports a staged addition-replacement strategy for extending catalyst life. No SCR system will require total catalyst change-out at the end of the guarantee period. (The commenter has provided data from certain operating installations and from quotes by one supplier.)

Response: One of the criteria for SCR evaluation in the study was not to use staged catalyst addition/replacement (refer to Section 3.1.1). This was a conservative approach, resulting in conservative cost estimates.

EPA recognizes that, for most power plants, a catalyst life management strategy would be desirable to extend the catalyst life. However, a system designed for staged catalyst addition/replacement would result in a larger reactor volume because of the presence of additional reactor layers required for such a design. This system may also have a relatively high pressure drop because of the increased pressure drop resulting from the loading of catalyst into the initially empty layers. For retrofit applications, the merits of a longer catalyst life would have to be evaluated against the potential need for additional space to accommodate a larger reactor and consequences of higher pressure drops.

Regardless of the above issues, EPA believes that exclusion of the life management strategy represents a more conservative approach that addresses the site-specific needs of a variety of SCR applications. Since this approach results in conservative cost estimates, its use is justifiable.

The SCR catalyst life and volume estimates for various applications in the study were conservatively based on the recent coal-fired experience in the U.S. and coal characteristics that require more conservatively sized catalyst volumes. Recent information from two SCR suppliers confirms the use of a 3-year guaranteeable catalyst life.

A review of the data presented by the commenter--specifically from operating installations--shows that the catalyst volumes in the EPA study generally agree with those in the data. EPA notes that the nonoperating catalyst volume data provided by the commenter appears to be low only because of the use of a catalyst life management strategy (which was not the basis for the EPA's figures).

4. In reference to Page 2-2, fourth paragraph, of the report, SCR system will not necessarily lead to excessive SO_2 to SO_3 conversion rates; SCR catalysts are available that oxidize less than 1 percent of the SO_2 to SO_3.

Response: EPA agrees that new catalysts have now become commercially available that minimize oxidization of SO_2 to SO_3. The excessive SO_2 to SO_3 conversion rate was specifically mentioned in the report in conjunction with applications requiring very high NO_x reduction rates (e.g., 87 percent for cyclone-fired boilers) and those where relatively high flue gas concentrations of SO_2 are present. For such applications, design measures, such as use of the aforementioned special catalysts, would become necessary. The section of the report referenced by the commenter will be revised to further explain this issue.

5. In reference to Pages 3-2 and 3-4 of the report, catalyst replacement volume rates shown on this page are high.

Response: The catalyst replacement volume rates shown in the report are based on a catalyst life of 3 years for coal-fired applications. As mentioned in the response to Comment 3 above, the design basis for the SCR systems in the EPA's study did not utilize a catalyst life management strategy. This approach does result in conservative catalyst replacement rates.

6. In reference to Page 4-1 of the report, a catalyst operating life of 5 years is low for natural gas service; a life of 8 to 10 years would be more representative of actual operating experience.

Response: EPA used an operating catalyst life of 5 years for which commercial guarantees can be obtained from different suppliers. EPA agrees that actual experience shows an operating life of longer than 5 years. However, unless such data can be backed up by commercial guarantees, using it to establish technology costs does not appear to be justified.

4.0 RESPONSE TO COMMENTS FROM BAKER & BOTTS

The comments were provided in a May 20, 1996, letter from Baker & Botts to Perrin Quarles Associates, Incorporated. The comments along with the reponses are provided below.

1. Use of the power factor scaling methodology in the EPA's report to project capital costs from the known cost of an SCR application to other different size applications is not valid. This methodology is viable for estimating costs for complete power plants, and not for single technology applications, such as SCR. EPA's costs show a substantial difference between the costs of SCR retrofits on 200 and 900 MWe plants. Since SCR lacks the

assumed economy of scale, there should be no cost difference between the 200 and 900 MWe systems.

Furthermore, the cost estimates available for SCR retrofit applications in the U.S. (at Merrimack and Mercer Stations) do not support the EPA's estimates. Even though the $/kW costs reported for Mercer (larger of the two installations) is lower than that for Merrimack, which tends to support EPA's methodology, this cost difference was for reasons other than the installation sizes. For example, the outdoor construction for Merrimack made it relatively easy to retrofit the SCR reactor into the proper location in the flue gas duct.

Response: EPA believes that the power factor scaling methodology used in its study reflects a practice commonly employed by the utility industry in determining capital costs for both complete power plants and individual equipment and technologies. As a result of investigations, EPA also finds that the cost models used in the EPA's estimates result in conservative costs for Group 2 NO_x controls. The following address various issues raised by the commenter:

- EPA notes that use of power factor scaling to develop costs for individual components or systems has been reported in numerous publications. One source has listed data from several publications (a total of 15) that confirms use of power law scaling factors for a large number of individual components and systems used in the chemical and pollution control systems (Ref. 1). This article alone provides substantial information to nullify the concern raised by the commenter.

  Another industry source has addressed the scaling factor issue specifically with regards to SCR costs (Ref. 2). According to this source, factors of 0.3 to 0.4 ($/kW basis) can be used to scale up the SCR costs. The SCR scaleup factors used in the EPA study are generally towards the lower end of the range recommended by this source, thus resulting in more conservative cost estimates for larger plants. This source clearly upholds EPA's use of the power factor scaling methodology.

  SCR retrofit costs for 122 to 750 MWe plants have been reported by another source (Ref. 3). This data shows a reduction in the SCR retrofit cost of approximately 48 percent between 122 and 750 MWe plants. The same source provides another example of SCR costs 100 to 375 MWe plants, showing a cost savings of approximately 41 percent for the larger plant. These reported cases show a greater reduction in the SCR retrofit costs for the larger plants than what would be obtained using the EPA's methodology. The commenter's claim that the SCR cost would not reduce for larger plants is therefore not valid.

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- EPA does not agree with the commenter's interpretation of the cost difference between the Merrimack's and Mercer's SCR installations. Contrary to the favorable retrofit conditions at Merrimack alleged in the comment, the SCR retrofit at Merrimack has been reported to be a difficult retrofit, which required addition of extensive flue gas ductwork to accommodate the SCR reactor. In addition, the baseline NO_x emission at Merrimack was 2.66 lb/MMBtu (compared with 1.8 lb/MMBtu for Mercer), and the system is designed to reinject 100 percent of ash to the furnace[4]. All of these factors resulted in an increased capital cost; the high baseline emission required a large ammonia storage and injection system and the concerns with high flue gas arsenic concentrations because of ash reinjection resulted in a larger and arsenic-resistant catalyst.

  EPA performed an analysis to compare the retrofit cost reported for Merrimack with those obtained from EPA's costing methodology. Attachment 1 presents the results of this comparison, which corroborates EPA's methodology.

2. EPA's report shows a pressure drop increase of 5 inches of water with the addition of SCR, without addressing any capacity derates associated with fan capacity limitations.

Response: All of the SCR cases in the EPA's report have assumed replacement of existing draft fans with larger fans to accommodate the additional gas side pressure drop. Therefore, a plant capacity derate would not be required with the larger fans. EPA recognizes that fan replacement would not be required for all retrofits. However, the cost for new fans was added as part of the SCR retrofit as a conservative measure.

5.0 RESPONSE TO COMMENTS FROM BLACK AND VEATCH

The comments were provided in a May 23, 1996, letter from Black & Veatch to Perrin Quarles Associates, Incorporated. The comments along with the responses are provided below.

1. The report should assume the use of a catalyst management plan for SCR systems. Using this plan reduces annual catalyst replacement cost by at least 65 percent. Such a plan can be incorporated by providing an extra layer in the SCR reactor for future catalyst addition. Even in the unlikely event of the inability to include a spare layer in the design, an effective catalyst management plan can be incorporated replacing individual layers. This also leads to substantial saving when compared with complete replacement at the end of catalyst life.

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Response: As mentioned in the EPA's response to the ICAC's Question 3, the decision to adopt an SCR design basis without a catalyst management plan was made on conservative grounds. Specifically, this design approach was used in consideration of those retrofit installations where the SCR reactor size and pressure drop may be important considerations.

EPA agrees that a catalyst management plan would be feasible for new installations and for many retrofit installations. Such a plan is expected to result in significant cost savings associated with longer catalyst life. However, EPA believes that an SCR design basis without this plan results in conservative cost estimates that reflects more-difficult-to-control retrofits.

2. Published data reporting results of SNCR installations does not support the report's assumption that SNCR has a NO_x reduction capability of 50 percent. SNCR has demonstrated capability for reliably removing 20 to 40 percent NO_x reduction on small to medium PC boilers while maintaining ammonia slip in acceptable ranges. (The commenter has quoted data from studies done by the commenter as well as published data from a 1996 ICAC forum held in Baltimore that show SNCR performance ranging from 30 to 40 percent.)

   Response: EPA disagrees that SNCR has not been demonstrated at NO_x reduction levels above 40 percent with acceptable ammonia slip levels. One source lists several coal-fired applications of SNCR where NO_x reduction levels of 50 percent and above were achieved (Reference 6). One of the listed coal-fired installations (WEPCO's Valley Power Plant) has been reported to have achieved 60 percent NO_x reduction with an ammonia slip of 5 ppm. The data quoted by the commenter also includes a coal-fired plant where NO_x reductions of up to 50 percent were demonstrated.

   EPA's report states that the SNCR system is capable of NO_x reductions of 30 to 50 percent. EPA agrees that not all candidate plants would be able to achieve NO_x reductions toward the higher end of this range with SNCR. For retrofit applications, this technology is heavily dependent on the existing boiler design and operating conditions, such as the flue gas residence time within an appropriate temperature range for reaction between the reagent and NO_x, temperature gradient at the reagent injection plane, baseline NO_x, etc. Any one of these factors can affect the effectiveness of SNCR.

   Experience with SNCR shows that substantial NO_x reductions (30 to 50 percent) are possible with this technology for coal-fired retrofit installations. EPA selected a 50 percent NO_x reduction level for this study to show the costs associated with the higher end of the SNCR performance. The next revision of the study will be based on an average SNCR NO_x removal efficiency of 40 percent.

EPA analyzed the effect of lowering NO_x reduction from 50 to 40 percent on the study costs. For this purpose, the operating costs were revised for the case with tangential-fired boilers firing coal. Even though the capital costs for the SNCR retrofit would decrease with a reduction from 50 to 40 percent NO_x, these costs were not changed (resulting in conservative levelized costs). The results of the analysis showed that, with an NO_x reduction from 50 to 40 percent, the cost effectiveness increased from $1,378 to $1,543/ton NO_x removed for a 200 MWe boiler and from $1,150 to $1,262/ton NO_x removed for a 900 MWe boiler.

The above comparison shows an increase in the total levelized costs of approximately 12 percent for the 200 MWe boiler and 10 percent for the 900 MWe boiler with the lower NO_x reduction level (40 percent). This is not a significant change in the total levelized cost.

3. The report does not discuss and reflect potential economic impacts caused by the ammonia slip from SNCR systems, such as forced outages and boiler load limitations. Experience has shown that numerous SNCR installations need relatively frequent off-line cleanings of the air heater when using SNCR with sulfur bearing fuels. Forced outages would be very expensive to accommodate especially during the summer peak season. (The commenter provides a reference to one SNCR installation and mentions another installation without a reference, in support of the comment.)

    Response: The commenter has not provided any proof of the claim that "numerous" SNCR installations have reported forced outages due to problems specific to this technology. Only one verifiable reference has been provided by the commenter to support this claim.

    One source lists several references of SNCR installations where this technology has been successfully applied (Ref. 6). As mentioned by this source and also indicated in references provided with the report (refer to Appendix A), the operating problems indicated by the commenter can be controlled by minimizing ammonia slip levels. Based on reported experience from many installations, EPA does not agree that forced outages due to ammonia slip are an inherent part of SNCR installations.

4. The capacity factor used (65 percent) in the economic analysis of the report is too low. Likely target baseload units operating during the 5-month "NO_x season" are likely to have very high capacity factors (85 to 95 percent) during this summer peak period. A misrepresentative value of 65 percent has a punitive effect on capital intensive technologies such as SCR.

    Response: EPA agrees with the commenter that plant capacity factors higher than 65 percent are likely during the summer peak period (5-month

"NO$_x$ season"). The use of a 65 percent factor is appropriate, however, because it represents a basis for comparison of the cost estimates.

5. Currently, this draft version appears to be heavily biased towards SNCR and against SCR when discussing post-combustion NO$_x$ control systems. We believe that it is misleading to imply that the installation of an SNCR system will reliably lead to 50 percent NO$_x$ reduction with ammonia slip less than 10 ppm with no potential for significant detrimental impact on plant operation.

    The bias against SCR is demonstrated in paragraphs such as the third complete paragraph on Page 2-2 where catalyst volume requirements are described as "significantly large" and SO$_3$ conversion rates are described as "excessive."

    Response: EPA does not agree that the study reflects any bias towards SNCR or against SCR. For coal-fired applications, the study clearly shows the SNCR technology to not be comparable to SCR. The SCR technology has been evaluated as the only technology capable of reducing NO$_x$ emissions to 0.15 lb/MMBtu. The SNCR technology has been evaluated only as a technology that can provide substantial NO$_x$ reductions. Such an evaluation cannot be termed as biased towards SNCR.

    The comment regarding the 50 percent NO$_x$ reduction with SNCR has been addressed in Item 2 above. The last item in the comment regarding catalyst volume and SO$_3$ conversion rates is a misinterpretation of the statements in the EPA's report. The term "significantly large" has been used in conjunction with the catalyst volume requirements for relatively high NO$_x$ reduction efficiencies required, especially for Group 2 boilers (e.g., an efficiency of 87 percent for cyclone-fired boilers). Increased catalyst volumes do result in increased capital costs. The SO$_3$ conversion rates have been mentioned in conjunction with high concentrations of SO$_2$ in the flue gas, which would require consideration of catalyst materials that minimize such conversion. Both of these items have been mentioned in terms of their impact on the cost. In the next revision of the report, these items would be clarified.

6.0 RESPONSE TO COMMENTS FROM NALCO FUELTECH

The comments were provided in a May 7, 1996, letter from Nalco Fueltech to Perrin Quarles Associates, Incorporated. The comments along with the reponses are provided below.

1. The treatment of capital costs may not appropriately reflect the cost to the utility plants subject to NO$_x$ control regulations. If a capital carrying charge of 0.115 was used in the report (as in the Group 2 boiler report attached as

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Appendix A), it would be too low compared with the commenter's experience of carrying charges from 0.145 to 0.200 for post combustion NO_x controls. In the deregulation and enforced competition environment, the utilities may have to carry capital for only 5 years, by the years 1999 and 2000, which would lead to higher carrying charges.

Response: The basis for the carrying charge is provided in the report in Table 2-1. As shown in this table, a carrying charge of 0.127 was used, based on information provided in the 1993 EPRI TAG (Ref. 7). This carrying charge is higher than 0.115 mentioned by the commenter. EPA recognizes that the carrying charge as well as other economic factors may differ for different applications. It would not be prudent to consider only one of these factors specific to certain installations and base other factors from different sources. For this study, it was necessary to utilize criteria that fit typical applications of NO_x controls. Therefore, the criteria presented in the EPRI TAG was used as the basis for this study.

EPA cannot agree with the commenter on the issue of the future direction of carrying charges in the power plant industry. An economic life of only 5 years as mentioned by the commenter is considered to be only a speculation, without any basis.

2. Since one premise for all the data in the report is that LNB or combustion modifications have already been employed, the gas reburning data may need to be revised in Table 1-5. The Acurex report entitled "Phase II NO_x Controls for the NESCAUM and MARAMA Region" states that cost effectiveness diminishes significantly for this add-on control because the NO_x reduction is only 20 percent when LNB is already installed.

Response: Experience does exist with gas reburning application on a boiler equipped with LNBs. At Public Service Company's Cherokee Unit 3, gas reburning was applied along with LNBs (Ref. 8). NO_x reduction associated with gas reburning alone was approximately 46 percent, well above the 20 percent level claimed by the commenter. The NO_x reduction achieved at this installation falls within the levels used for the study. Therefore, EPA cannot agree with the commenter's concern regarding the nonapplicability of this technology to units equipped with LNBs.

3. In Section 3.1.1 regarding SCR, the statement "It is assumed that the existing plant setting allows installation of the SCR reactors between the economizer and air heater without a need to relocate any major structure or equipment" is such an egregious leap, it is better to qualify the statement with the admission that installation on a number of sites would be impossible or imprudently costly.

Response: EPA is opposed to adding any statement in the report without a basis. Although it was impossible to evaluate the SCR retrofit potential to the entire boiler population considered in the study, data from several published sources indicates that SCR technology can be readily retrofitted to the majority of these boilers. EPA is not aware of any published source that has referenced power plants for which SCR retrofit is impossible (the commenter has not provided any references either).

During the evaluation of the rule for Group 2 boilers, public comments were received that provided an indication of the applicability of SCR to the boilers in general. One commenter provided results of an SCR retrofit feasibility survey done on cyclone-fired (Ref. 9) boilers. Of the 28 boilers in the survey, feasibility of SCR retrofit was confirmed on 25 boilers without relocation of major equipment or structures. Even for the remaining three boilers, it was reported that SCR retrofit was possible, although requiring long duct runs. EPA notes that the Merrimack installation (refer to Attachment 1) required extensive duct runs between the economizer outlet and air heater inlet, yet resulted in reasonable capital costs that corroborate the estimates provided in the EPA's study.

Another commenter (Tampa Electric Company) on the rule for Group 2 boilers provided results of a study (Ref. 10) that covered SCR application on a large number of boilers. Based on this study, SCR retrofit was feasible on all of these boilers. A large number of other commenters on the rule presented examples of SCR retrofittability to their boilers. Where cost data was provided by these commenters, EPA determined that any differences between this data and the costs reported by EPA were mostly due to different economic assumptions used by these commenters. In light of data available from so many different sources, EPA cannot agree with the commenter that SCR retrofit would be impossible or imprudently costly on a significant number of installations.

7.0 RESPONSE TO COMMENTS FROM NORTHEAST UTILITIES

The comments were provided in a May 24, 1996, letter from Northeast Utilities System to EPA. The comments along with the responses are provided below.

1. In general, the report is quite reasonable and complete. Some of the cost estimates are lower than we have used; some are higher.

    Response: EPA acknowledges the commenter's agreement with the study results. The cost differences are addressed below in the responses to specific comments on costs.

2. The SCR retrofit capital costs assume no allowance for relocating any existing structures or equipment. In general, this is a bad assumption.

Response: The study assumes that relocation of any *major* equipment or structure would not be required as part of the SCR retrofit. Cost allowances have been provided for relocation of minor equipment, ductwork, and piping. This assumption is considered reasonable, since the majority of new equipment required for SCR retrofit (tanks, pumps, vaporization system, piping, etc.) does not have to be installed in any specific location within the plant. The SCR reactor is located between the economizer outlet and air heater. For the majority of power plants, this reactor can be accommodated in the space above or on the side of the air heater (refer to the response to Comment 3 from Nalco Fueltech).

3. The report does not mention including costs for wastewater treatment facility modifications that might be required to handle SCR ammonia plant wastes and washwater wastes.

    Response: In the extensive published data available for operating SCR facilities, wastewater treatment problems due to ammonia contamination have not been raised as an issue for this technology. Even without SCR, ammonia storage and handling would generally be part of a power plant for water treatment purposes. Ammonia system for SCR would therefore pose no new issues for power plants in terms of handling any occasional spillages or leakages.

    The SCR systems are designed to minimize ammonia slip. The design basis used in the EPA's study was a maximum ammonia slip level of 5 ppm. At these levels, it can be expected that minimal amounts of ammonium salts would end up in the wastewater streams from washdown of equipment in the flue gas path. The reported SCR experience confirms this.

4. The coal unit sulfur content assumed in the report is only 0.8 percent by weight. Higher sulfur coal applications may result in air heater pluggages, incurring downtime costs and air heater capital work. SO_3 formation in the reactor can accelerate downstream corrosion and produce opacity plume/acid fallout problems.

    Response: The SCR system design in the report is based on restricting the ammonia slip to a level below 5 ppm. At this level of ammonia slip, problems due to formation of ammonium bisulfate, such as air heater pluggages, are not expected to occur (Ref. 6). In addition, catalysts are now commercially available that minimize oxidation of SO_2 to SO_3. EPA therefore does not believe that SCR poses a problem with regards to corrosion or opacity plume/acid fallout.

5. The levelized carrying charge factor assumed by EPA is only 60 percent of the value commenter would use.

Response: The carrying charge factor (0.127) used in the EPA's study has been taken directly from the 1993 EPRI TAG. This factor is based on a useful plant life of 20 years and a constant dollar approach. It should be noted that, based on a current dollar approach, the equivalent carrying charge factor would be 0.179, which is approximately 41 percent higher than the constant dollar factor used by EPA. Other economic assumptions, such as useful plant life, can also make a significant difference in the carrying charge factor value. Since the commenter has not provided the basis for commenter's carrying charge factor, EPA is not in a position to elaborate further.

The EPA's study applies to a variety of boiler applications. It is recognized that differences would exist in the economic factors applicable to different applications. However, EPA believes that the factor chosen from EPRI TAG yields reasonably accurate cost estimates for typical NO_x control installations.

6. The anhydrous ammonia cost assumption is about 20 percent less than experienced at Merrimack.

   Response: Ammonia costs used by EPA were derived from reliable sources that provided the average ammonia costs within the U.S. for the evaluation periods used in the study (refer to Section C.2 of Appendix A). Use of this average cost is considered more prudent for the study that covers a large population of boilers in this country.

7. No mention is made of the disposal cost of used SCR catalyst. Ash disposal costs are about 33 percent less than the commenter's experience.

   Response: The disposal cost of used SCR catalyst are part of the catalyst replacement cost (which will be noted in the next revision to the study). The ash disposal costs for the study are based on the cost data in the 1993 EPRI TAG.

8. The reported technology costs in the study do not match the commenter's experience; EPA's SCR costs are 20 to 25 percent lower for coal applications and about one-third lower for oil or oil/gas applications. The reported SNCR costs for oil or oil/gas units are more than 50 percent higher compared with the commenter's estimates.

   Response: The technology costs are highly dependent on the system design basis, equipment redundancy, and contingency factors used in the estimates. Since such information is not available for the commenter's cost estimates, EPA is not in a position to further address the cost differences quoted by the commenter.

9. Natural gas assumptions for reburn on oil unit should reflect the higher pricing more representative of noninterruptible gas contracts (typically 20 percent of total unit heat input).

    Response: The natural gas price used in the study reflected the 1995 price, and it was taken from a reliable published source (Ref. 11) This price reflects average price for gas paid by utilities.

10. Large variations in NO_x reduction equipment capital cost estimates on many of commenter's smaller units can be seen in the asymptotic scaling factors, which the report applies to units less than 200 MW. The same effect can be seen for levelized annual costs.

    Response: EPA agrees with the commenter that the costs increase at a higher rate as the unit size reduces, especially below 200 MWe. However, this is strictly because, for small units, even a modest reduction in size represents a significant percentage.

11. The report summary table for oil and gas fuels shows that SNCR is 50 percent or less of the cost of SCR on units of the commenter's size. This cost comparison is generally true for low and high capacity assumptions and on a basis of $/kW and $/ton of NO_x.

    Response: EPA acknowledges the commenter's agreement with the comparison shown in the study between SNCR and SCR.

12. Adding natural gas reburn to a pressurized unit can be a safety hazard. The report should mention such limiting application factors.

    Response: EPA disagrees with the commenter that gas reburn cannot be applied to pressurized units. Natural gas-fired boilers are generally designed for pressurized operation. Established industrial codes and standards exist to ensure that these boilers are designed and operated without compromising safety. Furthermore, gas reburning has already been successfully applied to a pressurized boiler (Ref. 8).

8.0   RESPONSE TO COMMENTS FROM HUNTON & WILLIAMS

The comments were provided in an August 7, 1996, letter from Hunton & Williams to EPA. The comments in this letter as well as in the report (Ref. 12) attached to this letter have been addressed below.

1. The key assumption in the EPA's analysis is the use of a power-law scaling relationship to project capital cost over a wide range of generating capacity and process conditions. Using this approach can introduce significant error if the range over which cost is projected is too large. Generally, the range

of extrapolation should be within a factor of two so as not to require changes in process design; otherwise an inappropriate design is considered as the cost basis.

Response: EPA has utilized a power-law scaling methodology for its cost estimates that is commonly used throughout the power and other industries. For all of the Group 2 boilers, the scaling factors were developed from cost estimates generated for two boiler sizes in each Group 2 category (for Group 1 boilers, appropriate factors were selected based on Group 2 boiler factors). A comparison with cost data from other published sources shows that these scaling factors result in more conservative cost projections for the boiler size range (refer to the response to Comment 1 from Baker & Botts).

The commenter's premise in restricting the range of cost extrapolation to a factor of two is based on the concern that for larger boilers the technology design basis would be different than that used for the smaller boilers. EPA does not share this concern. For larger boilers, any changes in the technology design basis would account for the increased boiler size (or flue gas volume); the equipment associated with the technology would increase in proportion to the increase in the boiler size. This does not amount to a change in the fundamental design basis for the technology retrofit.

The cost estimates presented in the EPA's study do not reflect the concern raised by the commenter. As shown in the cost curves attached to the study, the capital costs for the technology retrofits do not drop off rapidly for larger boilers. For example, the largest cyclone boiler size used in the estimation of SCR scaling factor was 400 MWe. Using the extrapolation range of two as recommended by the commenter, this scaling factor can be applied up to a boiler size of 800 MWe.

As shown in the study, the SCR capital cost for 800 MW is approximately $48/kW. For the largest cyclone boiler of 1,200 MW, using the scaling factor developed in the study, the capital cost projection is approximately $44/kW—a cost reduction of only 8.3 percent. It is obvious that, even if it were to be assumed that the SCR cost did not vary between 800 and 1,200 MWe boilers, there would be a negligible effect on the levelized costs. This same analogy applies to all of the cost estimates presented in the EPA's study.

2. The baseline NO_x rates assumed for the oil- and gas-fired boilers are 0.3 and 0.25 lb/MMBtu, respectively. Based on these levels, the study assumes that gas reburn and SNCR can be applied to achieve 0.15 lb/MMBtu NO_x level. However, the national boiler population may contain a significant number of units that produce NO_x in excess of the assumed rates. Also, reburn may be limited to 35 percent NO_x reduction for

those units where LNB and OFA are already present. SNCR may be limited to 35 percent NO_x reduction on sulfur bearing fuels. Subsequently, it can be concluded that SNCR and gas reburn are not capable of achieving the 0.15 lb/MMBtu limit on all oil- and gas-fired boilers.

Response: The possibility of selected NO_x controls not achieving the 0.15 lb/MMBtu limit on some boilers has been clearly recognized in the EPA study. As stated in Section 1.4, it has been noted that some boilers may be controlled to levels higher than 0.15 lb/MMBtu while others to levels below this limit.

3. Additional information is requested regarding key assumptions for the study: basis for 20 years remaining life, specification of space velocity for SCR, design concepts assumed to provide load following capability for SNCR, residence time assumed for the boiler population for reburn, and specifics of calculating levelized cost and cost per ton from information presented in the summary table.

Response: Responses to various comments raised are provided below.

- A remaining life of 20 years was assumed based on data reported in published sources as well as the power industry trend towards prolonged operation of older plants. High costs of new power plants and moves towards deregulation are expected to maintain a competitive environment that would make extended operations of older plants economically attractive.

  Use of a remaining life of 20 years is fully supported by published data. In one study, an economic life of 20 years was used for SCR retrofits at several plants in the Pacific Gas and Electric's system (Ref. 13). In another SCR study, the average economic life used for several plants in the Tampa Electric's system was 19.2 years (Ref .1).

- For all Group 2 boilers, sufficient information is provided in the study for estimation of space velocities; flue gas flowrate and the temperature at the economizer outlet are provided, and catalyst volume can be estimated from the annual replacement requirement multiplied by the 3-year life. For Group 1 boilers, catalyst volumes have already been provided. Flue gas flowrates and temperatures will be added in the next revision of the report.

- Design concepts for load following with SNCR are covered in Appendix A. Specifically, several levels of reagent injections are included for each application to provide the capability for varying the location of reagent injection with changes in the flue gas temperature profile as the boiler load changes. A microprocessor-based control

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system with boiler load feedback from the plant controls is included with each SNCR application. Automatic load following can be affected by these controls.

- The EPA's study assumes that gas residence times in excess of 0.25 second will be available for gas reburn.

- The methodology used for estimating the levelized costs has been described in detail in Appendix A. For each technology application, estimates of consumables are clearly listed that have been used in the estimation of levelized costs. Table 2-1 lists the economic factors for these costs.

4. Recognize and account for an approximately 20 percent of the oil- and gas-fired boiler inventory that will not be operating at RACT NO_x limits of 0.3 and 0.25 lb/MMBtu used in the study for these boilers, respectively.

   Response: Refer to the response to Comment 2 above.

5. The Title IV rule for Group 2 boilers specifies NO_x emission limits of 0.94 and 0.68 lb/MMBtu for cyclone and cell burner boilers, respectively. However, the study uses limits of 1.17 and 1.0 lb/MMBtu for these boilers. These higher rates increase capital cost and lower cost per ton of NO_x removed. Recommend use of Title IV limits for all boilers.

   Response: The baseline NO_x rates (1.17 and 1.0 lb/MMBtu) used for cyclone and cell-burner boilers represent the current average emission rates for these boilers. EPA will revise the costs to reflect the Title IV, Phase 2 NO_x limits.

6. The study covers the entire national utility boiler population, which makes it impossible to provide a detailed evaluation of each candidate boiler. EPA should recognize the uncertainty regarding application of the results of this study to the entire boiler population, and assign an appropriate margin of error. At a minimum, the study should also include specific process design (equipment lists/layout drawings) for each boiler category, and use of power-law derived costs should be limited to only small capacity changes.

   Response: EPA agrees that site-specific differences for the candidate boilers would affect the design requirements and costs for each technology application. However, the study was conducted with sufficient conservatism built into the technology design bases and cost estimates to address the variations expected between different boiler sites. EPA believes that the margin of error sought by the commenter is already built into this study. EPA also believes that use of the methodology and information generated for the Title IV, Phase 2 NO_x rule provided a credible

and effective base for the study to uphold accuracy of the study results. The concern regarding the power-law derived costs has already been addressed in the response to Comment 1 above.

7. EPA should further define the boilers that served as "baseline" for the analysis, disclosing site features, balance-of-plant equipment, and the anticipated process impacts.

    Response: EPA believes that the report includes sufficient information on each boiler to inform the reader of the basis for cost estimates. The information provided for each boiler includes design data, fuel analysis, and description of boiler backend equipment. In addition, needs for existing equipment modifications or replacements and other process impacts, such as changes in fuel and auxiliary power consumption, are clearly identified. The comment is not clear as to what additional information is being sought and for what purpose.

8. EPA should recognize a certain fraction of boilers feature site conditions that present a greater challenge than assumed for this analysis, and thus will incur higher costs. Accordingly, some boilers may require a premium for further "scope adders" beyond that assumed by the Bechtel database.

    Response: The commenter has not provided any example of requirements beyond those represented by "scope adders" listed in the study. Without specific reference to such requirements, it is not possible for EPA to address them. It should also be noted that contingency allowances have been included in each cost estimate for the study, which would provide coverage for additional requirements at certain sites (refer to the discussion in Attachment 1).

9. Even though the study claims use of the costing methodology in the EPRI TAG, it has ignored the requirement for AFDC (allowance for funds used during construction) included in the TAG. Since the construction period for SCR is anticipated to be 1 year, ignoring AFDC amounts to understating capital costs by nominally 5 percent.

    Response: The construction period for SCR retrofits would depend on the plant size as well as other site-specific conditions. For a relatively difficult SCR retrofit at the 330 MWe Merrimack installation, the total project schedule from authorization to proceed to completion of construction took only 11 months (Ref. 11) This schedule covered design, fabrication, delivery, and construction. Based on this experience, it is obvious that the 1-year construction period quoted by the commenter is excessive. Furthermore, even if 1 year is assumed to be applicable to certain special situations, the 1993 EPRI TAG used for the study recommends no AFDC allowance for construction periods of up to 1 year.

10. A capital recovery factor of 0.127 is appropriate for a remaining plant life of 20 years, and it is in accordance with the recommendation in the EPRI TAG. However, a remaining life of 20 years appears to be too high for the national boiler population. Recommend using a remaining life factor of 17 to 18, which would also require increasing the capital carrying charge from 0.127 to 0.14.

11. **Response:** The response to Comment 3 above has already addressed the comment on the remaining plant life. EPA fails to understand the recommended increase in carrying charge from 0.127 to 0.14 for a change in remaining life from 20 to 17/18 years. The commenter agrees with the EPRI's carrying charge factor of 0.127 for a 20-year life. However, the 0.14 factor is well beyond what the EPRI TAG shows for a remaining life of 17 or 18 years (0.130 and 0.129, respectively). It is to be noted that even if factors in the EPRI TAG for a 17- or 18-year life are used, they would not make any appreciable difference in the EPA's cost estimates.

12. In general, higher SCR retrofit costs would be expected for an application whose inlet NO_x concentration is greater than for another application. The cost estimates presented in the study do not follow this well accepted trend. The reported costs for wall-fired boilers are the same as those for cyclone or cell burner boilers, despite a significant difference in the inlet NO_x concentration for these boilers. This implies that the costs are under-reported for boilers with higher NO_x concentrations, especially the cyclone boilers. EPA should recognize the potential for errors in capital cost due to the selection of reference site and extrapolation from the Bechtel database over generating capacity and process conditions. These results further support UARG-suggested capital cost estimates (~ \$18/kW higher).

Response: The EPA agrees that inlet NO_x concentration would affect the SCR catalyst volume requirement and, therefore, the associated capital costs. However, the costs generated for one boiler category should not be compared with those for another category. For such a comparison to be valid, it would become necessary to use an exactly similar design basis for all boiler categories, including fuel, excess air rates, boiler efficiency, turbine configuration, main steam conditions, turbine heat rate, etc. In reality, differences exist between boilers in all of these factors, each one of which can affect the SCR design (and therefore the associated costs).

The differences quoted by the commenter in the reported cost estimates are due to the differences in the selected boiler designs and in the cost scaling factors. It is apparent that cost impacts of these differences have compensated for the cost differences due to inlet NO_x concentrations so that the costs reported for 200 MWe cyclone, cell burner, and wall-fired boilers are fairly close to each other. This also became possible because the total installed costs for SCR do not vary by large amounts between

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different inlet NO_x concentrations (or NO_x reduction efficiency requirements).

One source reporting the SCR costs for different NO_x reduction efficiencies shows a difference of approximately \$2/kW between efficiencies of 70 and 80 percent and \$4/kW between efficiencies of 80 and 90 percent (Ref. 14) for a 200 MWe plant. The differences are even smaller for a larger plant, which were used in EPA's estimates. As explained above, the effect of even small differences in the boiler designs and scaling factors on the SCR costs can easily equate to that caused by the differences in NO_x reduction efficiencies.

The objective of the EPA's study was to develop reasonable, representative costs for SCR retrofits. For this purpose, several conservative design assumptions were made and contingency factors were added to provide costs that cover a wide variety of conditions expected to be prevalent at various sites. Because of a variety of applications and design conditions, it was not possible to maintain exactly the same amount of conservatism in each cost. This led to apparent differences in technology costs when compared based on a single system parameter, such as reflected in the commenter's comment regarding the SCR costs for wall-fired, cell burner, and cyclone boilers.

EPA believes that the design basis used in its study for SCR applications has resulted in conservative costs. One factor used in this design basis was to exclude consideration of a catalyst life management strategy. As pointed out by other commenters on this report (ICAC and Black and Veatch), use of this strategy in the study could reduce the initial catalyst charge by as much as 20 to 75 percent and the overall catalyst replacement cost by at least 65 percent. In light of these comments, EPA cannot agree with the cost increase of \$18/kW suggested by the commenter.

13. NO_x reduction efficiencies of higher than 80 percent are not appropriate for coal- and oil- fired applications. Several factors may limit NO_x reduction capability to 80 percent, such as a need to maintain a strict limit (<3 ppm) of ammonia slip, achieving uniform NO_x and NH_3 mixing, and managing maldistribution in flue gas velocity.

Response: The commenter has failed to cite any references to support the 80 percent limit. EPA considers the concerns raised by the commenter to be speculations. Application of SCR to achieve greater than 80 percent and as high as 90 percent NO_x reduction efficiency has been reported for a large number of operating units (Ref. 15).

14. EPA should recognize that the increase in complexity of SNCR technology with greater generating capacity will negate any economies of scale, and employ the capital requirement developed at 200 MWe for all capacities.

Response: In the EPA's study, the costs were developed for boilers larger than 200 MWe. For example, the boiler size used for tangential boiler firing coal was 348 MWe (refer to Table 3-1). The design basis used for SNCR takes into consideration the items quoted by the commenter for larger boilers. It is therefore not understandable why the economies of scale would not apply to SNCR. Additionally, the scaling factors used in the study do not result in significant cost reductions for larger boilers, similar to the case described earlier (refer to the response to Comment 1 above).

15. EPA should recognize that the SCR costs projected are applicable to natural gas firing. A cost premium should be included for applications to sulfur containing fuel oil.

Response: The study has addressed the oil and gas firing applications for SCR separately. Appropriate design factors have been used for these two fuels, with consideration given to sulfur content in oil. The reported capital costs for SCR application on oil are significantly higher than those on gas.

16. For both SNCR and reburn on gas and oil firing, the potential for requiring increased complexity for either reagent or reburn fuel injectors with higher capacity may negate any economies of scale. Thus, capital requirements developed at 200 MWe should be applied to all capacities.

Response: Both boilers used for gas- and oil-fired applications were 350 MWe. (Refer to the response to Comment 14 above for further justification of EPA's approach.)

17. The assumptions that coal reburn, SNCR, and natural gas reburn on coal firing cannot provide sufficient NO_x reductions to achieve 0.15 lb/MMBtu limit are appropriate.

Response: EPA acknowledges the commenter's agreement with the study approach regarding coal and gas reburn and SNCR applications on coal-fired boilers.

18. On coal and oil applications, SNCR should be limited to 25 to 30 percent NO_x reduction.

Response: SNCR technology has been demonstrated to achieve NO_x reduction levels of 30 to 50 percent (Ref. 6) which was used as a criterion for this study. EPA cannot agree with an arbitrary limit of 25 to 30 percent

set by the commenter (refer to the response to Comment 2 from Black and Veatch).

19. The report should identify the following:

   •, Specified limit (if any) on conversion of SO_2 to SO_3

   • Presence of an economizer bypass

   •, Fraction of the boiler population that must address unusual site features, and significant equipment location

   Response: The study was based on the methodology used in deriving the NO_x control costs for the Group 2 boiler rule. The Group 2 boiler report was attached to this study as Appendix A. This report does address the above comments: the design basis for SCR restricted SO_2 to SO_3 conversion to a maximum of 1 percent and an economizer bypass is provided with each SCR application. The design basis for the study did not assume any major equipment relocation as part of SCR retrofit. In light of extensive published literature showing no need for such relocations, the EPA considers this assumption to be valid (refer to the response to Comment 3 from Nalco Fueltech).

9.0 REFERENCES

1. Remer, et. al., "Air Pollution Control: Estimate The Cost Of Scaleup," *Chemical Engineering*, November 1994,

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3. Cichanowicz, et. al., "Factors Affecting SCR Capital Costs For Utility Boilers," Handout, Meeting with EPA, December 20, 1993.

4. Owens, et. al., "SCR Retrofit for NO_x Control at a Wet Bottom Boiler," 1995 Joint Symposium on Stationary Combustion NO_x Control, Kansas City, Missouri.

5. Philbrick, et. al., "SCR System at Merrimack Unit 2," March 1996 ICAC Forum, Baltimore, Maryland.

6. SNCR Committee, Institute of Clean Air Companies, Inc., "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions," July 1994.

7. "Technical Assessment Guide," EPRI, Volume I, Revision 7, 1993.

8. Folsom, et. al., "Three Gas Reburning Field Evaluations: Final Results and Long Term Performance," 1995 Joint Symposium on Stationary Combustion NOx Control, Kansas City, Missouri.

9. "Supplemental Comments for Group 2 Boiler NO_x Emission Limits," by J. E. Cichanowicz, prepared for UARG, June 1996.

10. "Nitrogen Oxide Limitation Study," by Carnot/Sargent & Lundy, prepared for Tampa Electric Company, March 15, 1996.

11. "Energy Analysis: 1995-01," American Gas Association, January 13, 1995.

12. "Summary of Comments For the Draft Report Prepared for US EPA by Bechtel/Cadmus," by J. E. Cichanowicz, prepared for UARG, July 13, 1996.

13. Veerkamp, et. al., "Evaluation of SCR as a NO_x Control Option for Pacific Gas and Electric," 1993 Joint Symposium on Stationary Combustion NO_x Control, Miami Beach, Florida.

14. "Evaluation of NO_x Removal Technologies - Volume 1, Selective Catalytic Reduction," by Burns and Roe Services Corp., Prepared for US DOE, September 1994.

15. SCR Committee, Institute of Clean Air Companies, Inc., "White Paper: Selective Catalytic Reduction (SCR) To Abate NO_x Emissions," October 1994.

ATTACHMENT 1

CORROBORATION OF THE CAPITAL COST

FOR

MERRIMACK'S SCR INSTALLATION

CORROBORATION OF THE CAPITAL COST
FOR
MERRIMACK'S SCR INSTALLATION

For the 330 MWe Merrimack installation designed for a 65 percent NO_x removal efficiency, the total capital cost was reported at $56/kW (Ref. 1, 2). Also, space limitation at this site required addition of a significant amount of additional ductwork and support steel for this retrofit. The baseline NO_x emission for this unit was also unusually high (2.66 lb/MMBtu), thus requiring a relatively large and expensive ammonia handling system.

The information available from Merrimack was used to corroborate the costing methodology used in the EPA study. A comparison of the Merrimack cost with the EPA-reported costs requires some adjustments in EPA's costs, because of the differences in the design NO_x reduction efficiency (65 versus 50 percent) and the baseline NOx emission levels (2.66 versus 1.3 to 1.4 lb/MMBtu). The comparison strategy consisted of developing a capital cost based on design criteria similar to Merrimack while using the EPA costing methodology (Ref. 3). The capital cost developed with this approach could then be compared with the actual Merrimack cost for validation purposes.

Table 1 shows an equipment list for the Merrimack installation. This list has been prepared from published information (Ref. 1, 2) and information received by EPA from the system supplier (Ref. 4). It should be noted that this installation did not require some of the existing plant modifications that were included for the boilers used in the EPA study (e.g., replacement of the existing draft fans and an economizer bypass). However, being a moderately difficult installation, Merrimack did require extensive flue gas ductwork to accommodate the SCR within the existing setting and a bypass around the SCR reactor.

Table 2 shows the capital cost estimate for the Merrimack retrofit. This estimate utilizes the same cost model that was used to generate costs for the EPA study. As shown in Table 2, the total plant capital requirement is $68.53/kW, which is higher than the actual cost reported for Merrimack of $56/kW. Thus, this comparison confirms the conservatism used in the cost methodology utilized in the EPA study.

It should be noted that the estimated cost in Table 2 is higher than the reported cost by approximately $12.5/kW. This difference is greater than the combined

value of the process and project contingencies (which is $11.3/kW). This comparison supports the EPA's belief that the contingencies used in the EPA's cost estimates can cover any additional costs that might, in rare cases, be incurred at certain atypical installations because of site-specific factors.

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1. B. Owens, et. al., "SCR Retrofit for NOx Control at a Wet Bottom Boiler", 1995 Joint Symposium on Stationary Combustion NOx Control, Kansas City, Missouri.

2. Philbrick, et. al., "SCR System at Merrimack Unit 2", March 1996 ICAC Forum, Baltimore, Maryland.

3. "Investigation of Performance and Cost of NOx Controls as Applied to Group 2 Boilers", Draft Report, August 1995, EPA Contract No. 68-D2-0168.

4. Conversations between R. Srivastava of EPA and S. Khan of Bechtel, August 1996.

Table 1

MAJOR EQUIPMENT LIST
MERRIMACK SCR
ANHYDROUS AMMONIA-BASED
BOILER SIZE: 330 MW

#	Item	Description/Size
1	SCR reactor	Vertical flow type, 1,615,350 acfm capacity, equipped with a plate type catalyst with 14,124 ft^3 volume placed in two layers, insulated casing with two empty layers for future catalyst addition, sootblowers, hoppers, and hoisting mechanism for catalyst replacement
3	Anhydrous ammonia storage	Horizontal tank, 250 psig pressure; 87.5-ton storage capacity
2	Compressors	Rotary type, rated at 400 scfm and 10 psig pressure
2	Electric vaporizer	Horizontal vessel, 450 kW capacity
1	Mixing chamber	Carbon steel vessel
1 Lot	Ammonia injection grid	Stainless steel construction
1 Lot	Ammonia supply piping	Piping for ammonia unloading and supply, carbon steel pipe: 4.0 in. diameter, 600 ft long, with valves, and fittings
1 Lot	Air ductwork	Ductwork between air heater, mixing chamber, and ammonia injection grid, carbon steel, 400 ft long, with two isolation butterfly dampers, and expansion joints

Table 1 (Continued)

MAJOR EQUIPMENT LIST
MERRIMACK SCR
ANHYDROUS AMMONIA-BASED
BOILER SIZE: 330 MW

#	Item	Description/Size
1 Lot	Sootblowing steam piping	Steam supply piping for the reactor sootblowers, consisting of 200 feet of 2" diameter pipe with an on-off control valve and drain and vent valved connections
1 Lot	Flue gas ductwork modifications	Ductwork modifications to install the SCR reactors, consisting of insulated duct, isolation damper, turning vanes, and expansion joints
1 Lot	SCR bypass	Ductwork consisting of insulated duct, 12'x24' double-louver isolation damper with air seal, and expansion joints
1 Lot	Ash handling modifications	Extension of the existing fly ash handling system modifications, consisting of one slide gate valves, one material handling valves, one segregating valve, and ash conveyor piping, 180 ft long with couplings
1 Lot	Controls and instrumentation	Stand-alone microprocessor based controls for the SCR system with feedback from the plant controls for the unit load, NO_x emissions, etc., including NO_x and ammonia analyzers, air and ammonia flow monitoring devices, and other miscellaneous instrumentation

Table 1 (Continued)

MAJOR EQUIPMENT LIST
MERRIMACK SCR
ANHYDROUS AMMONIA-BASED
BOILER SIZE: 330 MW

#	Item	Description/Size
1 Lot	Electrical supply	Wiring, raceway, and conduit to connect the new equipment and controls to the existing systems
1 Lot	Foundations	Foundations for the equipment and ductwork/piping, as required
1 Lot	Structural steel	Steel for access to and support of the SCR reactors and other equipment, ductwork, and piping

Table 2
RETROFIT CAPITAL COST ESTIMATE SUMMARY FOR
SCR MODIFICATIONS MERRIMACK BOILER

NO_x Control Technology		SCR
Boiler Size (MW)		330
Cost Year		1994
Direct Costs ($/kW):		
SCR Reactors/Ammonia Storage		31.3
Piping/Ductwork		13.1
Electrical/PLC		3.1
Draft Fans		0.0
Platform/Insulation/Enclosure		1.1
Total Direct Costs ($/kW):		48.6
Scope Adder Costs ($/kW)		
Asbestos Removal		0.0
Transformer		0.0
Air Heater Modifications		0.0
Boiler System Structural Reinforcement		0.0
Total Scope Adder Costs ($/kW):		0.0
Total Direct Process Capital ($/kW):		48.6
Indirect Costs:		
General Facilities	5.0%	2.4
Engineering and Home Office Fees	10.0%	4.9
Process Contingency	5.0%	2.4
Project Contingency	15.0%	8.7
Total Plant Cost (TPC) ($/kW):		67.1
Construction Years		0.0
Allowance for Funds During Construction		0.0
Total Plant Investment (TPI) ($/kW):		67.1
Royalty Allowance	0.00%	0.0
Preproduction Cost	2.00%	1.3
Inventory Capital	Note	0.13
Initial Catalyst and Chemicals	0.00%	0.0
Total Plant Requirements ($/kW):		68.53

NOTE: Cost for anhydrous ammonia stored at site.

ATTACHMENT 2

COPIES OF COMMENTS RECEIVED FROM PUBLIC

May 20, 1996

Ravi Srivastava
U.S. EPA
Mail Drop 6204J
401 M Street SW
Washington DC 20460

Subject: Comments on EPA Draft Report, "Cost Estimates for Selected
           Applications of NO_x Control Technologies on Stationary Combustion
           Boilers"

Dear Mr. Srivastava:

Attached are our comments on the subject report, along with marked-up pages.

Please feel free to discuss these comments with us.

Sincerely,

Arthur L. Baldwin
Program Coordinator
NO_x Control Technology
Office of Clean Coal Technology

Dennis N. Smith
Technical Analyst
Office of Clean Coal Technology

Enclosure

COMMENTS ON DRAFT REPORT TITLED
"COST ESTIMATES FOR SELECTIVE APPLICATIONS
OF NO$_x$ CONTROL TECHNOLOGIES
ON STATIONARY COMBUSTION BOILERS," Dated March 1996

General Comments

This draft report was prepared by Bechtel Corporation for the U.S. EPA. Attached to the draft is Appendix A, titled "Investigation of Performance and Cost of NO$_x$ Controls as Applied to Group 2 Boilers, Draft Report," dated August 1995. The present review covers both the new text and Appendix A.

We had commented previously (August 1995) on the July 1995 draft of Appendix A. The current version reflects most of the changes we proposed at that time. As such, it represents a great improvement over the earlier draft. Although we feel it would have been preferable to reorganize Appendix A along the lines we suggested previously for easier access to the material, it appears that this is not likely to happen. On the one hand there is still considerable duplication, while on the other hand it is necessary to search in more than one place for information on a given topic.

A related problem is the numbering of the pages. Taken out of context, one cannot readily determine where a page numbered, for example, 3-2, belongs, since both the new main text and Appendix A follow the same numbering system. It would be helpful to insert an A in front of each page number in Appendix A.

Adding to the complication is the existence of two Appendix A's. As stated above, Appendix A is attached to the new document dated March 1996. Appendix A, however, also contains an Appendix A consisting of the EPA database for Group 2 boilers. A simple way to correct this might be to rename the EPA database Appendix AA, and number the pages accordingly. There are only a few pages in the

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EPA database, and there is little if any cross-referencing to this material in the remainder of the text.

Despite these shortcomings, the August 1995 version of Appendix A, along with Appendices B and C, provides useful information on a variety of NO_x reduction technologies, and should be helpful in the rule making process as applied to Group 2 boilers.

Scope of Main Report

A more important issue, however, is the scope of the March 1996 report, "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," referred to in the present review as the main text. As stated in the second bullet item in Section 1.1, p. 1-1, one of the objectives of the present study is to develop costs for NO_x control technologies applicable to tangentially-fired and dry bottom wall-fired boilers, which are Group 1 boilers. However, Appendix A, by definition, deals only with Group 2 boilers. Thus one of the shortcomings of the main text is that there is no documentation for the treatment of Group 1 boilers.

Moreover, the first bullet item in Section 1.1, p. 1-1, addresses more stringent NO_x controls than had been promulgated in Phase I, namely an emissions level of 0.15 $lb/10^6$ Btu, again without background documentation for the costs of achieving this degree of control. Furthermore, no basis is given for the selection of the 0.15 $lb/10^6$ Btu target.

The problem of overall orientation becomes critical on p. 2-1, where the first bullet item near the bottom of the page refers to the various components of the systems studied, including low-NO_x burners (LNB), overfire air (OFA), and gas recirculation fans. The statement, "Where applicable, the study burners are already equipped with low-NO_x burners" is unclear. What constitutes cases where

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LNBs are applicable? Where are they not applicable? If such combustion modifications are already in place, is the application of other technologies not "possible," as stated in the draft, or not economically justified?

Related to these questions of scope is the whole issue of including OFA as a combustion modification technology. The EPA was severely criticized in the past for assuming that OFA should be included with LNBs for NO_x control. By appearing to link these technologies now, will the EPA be subjected to the same criticism again? Thus this potentially very significant bullet item is misleading as now worded; it needs clarification and amplification.

Throughout the new text, technologies for NO_x removal are selected for a given boiler application without much explanation. Presumably other technologies would also be appropriate in some instances, and in fact some of these are analyzed in the Appendices. Without additional information, it would appear that the report is biased in favor of SNCR. While we do not necessarily disagree with the choices made, we feel there is insufficient discussion to inform the reader regarding the chosen technologies. If certain technologies were considered and rejected, reasons should be given. If, on the other hand, time or budget constraints precluded examination of other technologies, this should be stated.

Because of questions such as these, it would be helpful to include an introductory paragraph putting the whole document into perspective and orienting the reader as to the scope and purpose of the current report.

Specific Comments

Economics Methodology Appendix A ("Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers," dated August 1995) now incorporates the correct method of developing

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process economics. This treatment includes all the relevant com-
ponents of levelized costs, as discussed in our review of the
earlier draft. However, the new main text refers to calculations
for levelized costs both with and without the capital charge com-
ponent, although it is not clear where these calculations are
presented other than in Table 1-2.

All of the costs for Group 2 boilers reported in Appendix A cor-
rectly include capital charges in the levelized costs, as presum-
ably do the costs given in Tables 1-3 and 1-4 of the main text.
Unless there is some compelling reason to the contrary, we recom-
mend eliminating all references to two versions of levelized costs.
We would be glad to discuss this question with the authors of the
document.

Tables 1-3 and 1-4 contain some cost estimates for which there is
no supporting documentation. This presents a problem for readers
who wish to verify or adjust the figures based on alternative input
data. Moreover, to the extent that it is feasible to find cases
documented in the Appendices, the figures do not seem consistent.
For example, Table 1-3 shows a levelized cost of $695/ton for SCR
as applied to a cyclone boiler at a capacity of 200 MW and a 65%
capacity factor. Figure 4-21 in Appendix A shows a value of about
$625/ton at the same capacity and capacity factor. What are the
reasons for the difference? If these cases are not meant to be
compared, what is the difference in methodology? Which figures
should the reader use in planning a NO_x control strategy?

Technology Selections The Table of Contents for Appendix B (p. B-
i) is quite useful, since it presents at a glance the NO_x reduction
technologies evaluated for the separate boiler types. Thus, for
cell-burner boilers, the technologies are plug-in low-NO_x burners
and non plug-in low-NO_x burners. For cyclone boilers, the technolo-
gies are coal reburning, gas reburning, SNCR, and SCR. It would be
helpful if the NO_x control strategy were also given for wet-bottom

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boilers and vertical, dry-bottom boilers (SNCR in both cases). The reader could thereby quickly find a discussion of any particular technology of interest.

Capital Costs The capital cost for the SCR process given in Table B4-18 (p. B4-72) is of the correct order of magnitude, but the presentation is potentially misleading in that there is no cost given for the catalyst installed in the reactors. While the cost for reactors and ammonia storage is given as $22/kW (for a 150 MW plant), our work on SCR has shown that the major portion of that cost is in fact the initial catalyst inventory, which is a large figure due to the high unit price of the catalyst. While the bottom line would not change, it would be more accurate to show the catalyst inventory as a separate line item at the appropriate place in Table B4-18 and reduce the capital cost for reactors/ammonia storage by the same amount.

As pointed out above, background information on NO_x control for Group 1 boilers is missing. This includes capital costs.

In Table 1-2, the second column lists capital costs in $. Should this be $/kW?

Levelized Costs Appendix B now presents a breakdown into the major components of levelized costs, which had been missing previously. While the format does not show sufficient detail to permit verification or adjustment of the individual figures, it is helpful to have even this much of a breakdown, showing at a glance the relative contributions of the several cost components. Note that the tables giving levelized costs, including the one on p. B3-6 and continuing throughout the document, would be more readable if the columns under $/ton NO_x were right justified.

On p. 4-3 of Appendix A, item 6 refers to the fact that the levelized cost estimates "consider" several factors. This sounds too

casual for a clearly defined calculation. A more definitive word such as "include" is recommended since it would be entirely unambiguous in this context. Otherwise the reader cannot be sure that all the factors "considered" are actually included, as indeed they must be in order to perform the calculations correctly.

On p. 1-2 of the main text, last bullet item, there is reference to economic factors "reported" in the EPRI TAG. As we pointed out previously, any economic factors given by EPRI are only examples and are not meant to be recommendations. In the context of the present report, to avoid any implication that these numbers are anything other than representative values, we suggest simply using the term "listed" or "given."

On p. B2-8, the first paragraph in Section 2.4.2 contains a sentence about estimating the capital-related components of levelized costs "along with the predicted capital costs for the boilers within the corresponding range." This statement is very confusing. The economics of NO_x reduction technologies are independent of the cost of the boiler on which the technology is installed. If something else is meant here, it should be clarified. If not, the statement should be eliminated.

Capacity Factor In the main text, Section 1.3 mentions two assumed values for capacity factor: 65% and 27%. While the economic calculations reported in Tables 1-3 and 1-4 appear to handle these two capacity factors properly in terms of $/kW and $/ton of NO_x removed, it is not clear how the mills/kWh figures in Table 1-2 reflect these different assumptions. Even if the NO_x control technology is operated only five months out of the year, the power plant generates electricity at its normal rate for the entire year. To avoid possible misinterpretation or confusion on the part of utilities seeking guidance from this document, the basis for the mills/kWh calculations should be checked carefully and explained in greater detail in this section.

Sensitivity Analyses As we pointed out previously, the sensitivity analyses for critical process variables given in Appendix B are useful in principle but are, in fact, of limited value because the conclusions drawn are a function of the ranges of the variables investigated rather than reflecting their true significance.

For example, it is stated in several places that reagent cost is not an important variable in SNCR, although it can easily be seen that reagent cost is a large component of SNCR levelized cost. Likewise, it is stated in a number of places (for a variety of technologies) that capital cost variation has a minor impact on capital (and levelized) costs. This is fallacious reasoning, and results from the fact that only a narrow range of capital costs (±5%) was investigated. Similarly, catalyst replacement cost is a significant component of SCR economics, as shown on p. B4-24, but the statement on p. B4-25 does not support this obvious fact.

The impact of any variable can be made unimportant if a narrow enough range is evaluated. In the case of reagents, it is of course reasonable to explore only the range of prices likely to be encountered. A more meaningful approach would be to say that an x percent range of reagent prices was selected for the sensitivity calculations, representing a realistic degree of variation, and that within these limits, the effect on levelized cost was found to be y percent.

In principle, cost sensitivity effects should be compared on a relative basis. What is important is the percent increase in process capital or levelized cost for a given percent increase in a particular process parameter. If costs go up 5% for a 5% increase in a parameter, then that parameter is important even though a 5% increase is small.

As pointed out previously, the graphs presenting the sensitivity analyses, showing the variation in costs at two levels of a par-

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ticular variable, lack labels on the two individual curves. Thus, a reader looking at the graphs is forced to refer to information located elsewhere in the report to determine the values of the variables being studied. This is true for Figures B3-6 through B3-11, B3-17 through B3-22, B4-6 through B4-13, B4-19 through B4-30, B4-36 through B4-45, B4-51 through B4-61, B5-6 through B5-15, and B6-6 through B6-15. Adding labels to the individual curves would be a simple matter and would greatly increase the usefulness of these graphs and of the document as a whole.

SNCR Process The section on chemical type and stoichiometry, p. C-39, is much improved over the previous version. However, it is still not clear why the use of urea has an advantage over ammonia in large boilers. Isn't the same stoichiometric effect valid for all boiler sizes? Are there other factors related to boiler size?

Definitions Since the main text deals with both Group 1 and Group 2 boilers, it would be helpful to explain these terms. Group 2 boilers are defined by reference to the Appendices, but there is no definition of Group 1. A simple way to do this would be to insert subheadings in Table 1-1, showing both groups of boilers.

Likewise, there are no references to Phase I or Phase II of the NO_x control implementation plan, although the target NO_x levels can be related to the two phases.

Throughout the report, costs are variously given in mills/kWh and mils/kWh. The dictionary definition calls for the use of mills to represent 1/1000 of a dollar. We recommend making the appropriate changes, using a search function in your word processing program. We did not mark every page where this inconsistency occurs. Note also that the captions on some of the figures use the term mils and should be corrected if possible.

On p. B3-2, the word "mils" is used in reference to pulverizers. Clearly, this needs to be corrected to say "mills."

Significant Figures In Tables 1-3 and 1-4, the capital costs show too many significant figures. Considering the accuracy of the calculations, two significant figures would be maximum. Making this change would also make these tables more readable. Likewise, at various points in the text, boiler efficiencies could be reported to the first decimal; the tables from which these values are derived should, of course, continue to show two decimal accuracy.

Miscellaneous Items in Main Text In Section 2.1, first paragraph, there is reference to Table 1-2. This should be Table 1-5. The second sentence states that this table shows variations in NO_x reduction effectiveness on a site specific basis. This is not quite true. The table shows a range of effectiveness for each category. The text would be more clear and accurate if it said, "As shown in this table, the NO_x reduction effectiveness for each technology varies over a significant range. These variations are a result of site specific factors."

Section 2.3, second bullet item, refers to Section 2.4.1 of Appendix A. There is no such section.

Other editorial comments are noted on the marked-up sheets.

h. The costs for inventory capital apply only to the SNCR and SCR technologies where chemical reagents will be stored on-site. These costs are based on a 14-day storage of the reagent in each case.

i. The allowance for funds during construction (AFDUC) was assumed to be zero for the following reasons:

- The AFDUC depends on the payment terms agreed upon between the buyer and the equipment suppliers, which may vary considerably between various applications.

- The construction period for all technologies is estimated to be less than a year.

- Even for the technologies with significant capital investments, such as SCR and coal reburning, any AFDUC would be negligible, especially because of the short construction period.

The technology retrofit design requirements are expected to vary with different installations. Site-specific factors may influence not only the design requirements pertaining to the technology components, but also the required modifications of existing equipment.

The conceptual designs developed for each study case were based on site conditions applicable to a typical Group 2 boiler. In some cases, additional requirements may be imposed because of special limitations prevailing at certain sites. Based on the experience with these technologies at existing installations, these additional requirements have been anticipated and shown in the cost estimates as scope adder items.

The scope adder costs have not been included in the costs shown on the figures. The contingencies provided in the cost estimates generally cover these additional costs. It is, therefore, assumed that the costs incurred by a few plants requiring any of the scope adder items would still fall within the predicted ranges in this report.

2.3.2 Levelized Cost Estimates

For each technology retrofit, the levelized cost estimates ~~consider~~ *include* the following components:

- Carrying charges for the capital costs

- Increases in fuel costs associated with the retrofit technology

2.4.2 Scaling of Levelized Costs

The levelized costs are made up of various components. Of these, the carrying charges and maintenance costs are a direct function of the capital costs. These components can, therefore, be estimated using the pertinent economic factors along with the predicted capital costs for the boilers within the corresponding range.

For the other levelized cost components, a statistical curve fitting approach was followed to define the variation in each component value with respect to changes in the boiler size. Two points for this curve fitting exercise were available for each component from the data generated for the two generic boilers. A third point on the curve was assumed to be the zero point (i.e., for a unit size of zero MW, each component assumed a value of zero).

2.4.3 Reported Cost Data

The scaling factors were used to generate curves showing the variation in the capital and levelized costs with respect to changes in the boiler size. For each study case, the following three curves were developed:

- Capital cost in $/kW versus unit size

- Levelized cost in mils/kWh versus unit size

- Levelized cost in $/ton of NO_x removed versus unit size

2.5 SENSITIVITY EVALUATIONS

The costs reported in this study were based on certain assumptions and specific economic factors described earlier. Sensitivity evaluations were conducted to analyze the impact of varying some of the critical system design parameters and economic factors.

Appendix C of the main report provides detailed discussions on various parameters and factors whose variations can have an impact on the design and performance of the NO_x control technologies. Table B2-3 lists some of the critical parameters and factors for which sensitivity evaluations were performed. The range values assigned to each parameter for this evaluation are also provided in Table B2-3.

The ranges for the parameter values in Table B2-3 were established as follows:

a. The capital cost estimates for each technology include a 15 percent margin for project contingency and a 5 percent margin for process contingency. Since these margins already cover possible cost increases for the Group 2 boiler applications, there is a low potential for variations beyond these

either to achieve proper NO_x reductions or to install the technology components. These factors include lack of sufficient space to install the reburn fuel injectors (or burners) and overfire air ports, lack of proper residence times, and unavailability of natural gas.

- The effectiveness of the SNCR technology can vary from 30 to 50 percent. Based on the NO_x reduction needs (0.15 lb/MMBtu) of the study boilers, this technology can be applied only to the gas- and oil-fired boilers. Similar to gas reburning, this feasibility may be subject to site-specific factors. The most important aspect of SNCR is the availability of a proper residence time within the boiler in a required temperature zone, which varies with the type of SNCR system used (ammonia- or urea-based). It is recognized that such residence times may not be available in all gas- and oil-fired boilers.

- The NO_x reduction needs of all study boilers fall within the potential effectiveness range (80 to 90 percent) for the SCR technology, which is therefore considered feasible for all of these boilers.

  Even for the SCR technology, the NO_x reduction rates required for the cell, cyclone, wet bottom, and vertically fired boilers are relatively high. Such rates would require significantly large amounts of catalyst. Other concerns, such as excessive SO_3 conversion rates, may also be applicable in some specific retrofits.

  In some cases, the duty on the SCR systems could be reduced by applying more than one NO_x control technology. For instance, hybrid systems using SNCR and SCR could be used, or SCR could be applied with combustion controls (applicable to cell, wet bottom, and vertically-fired boilers). These applications are considered outside the scope of the study.

- Based on the above analyses, the technologies selected for meeting the 0.15 lb/MMBtu limit include SCR for all boiler categories and SNCR and gas reburning for gas- and oil-fired boilers only. Similarly, SNCR has been considered for achieving substantial NO_x reduction (50 percent) for the wall-fired and tangential boilers burning coal.

2.2 Technical Evaluations

The methodology for the technical evaluations is essentially the same as used in the previous study (Appendix A, Section 2.0 of Appendix B). The highlights of this methodology are as follows:

- All design details pertaining to the representative boilers in the cyclone, cell, wet-bottom, and vertically fired categories are the same as shown in the previous study.

- Since the tangential and wall-fired boilers burning coal, oil, or gas were not included in the previous study, design details of representative boilers for these categories have been specifically developed for this project from the Bechtel in-house database. In the case of each boiler category, the evaluations are performed using one representative boiler. It is assumed that boiler design parameters vary in a direct proportion to the boiler size.

3.0 COAL-FIRED PLANT ASSUMPTIONS AND RESULTS

This section summarizes the technical and economic evaluations conducted for the coal-fired boiler applications of NO_x control technologies.

3.1 Tangential Boiler Applications

The NO_x control technologies evaluated for this boiler type include SCR and SNCR. The design data for the representative boiler selected for this evaluation are shown in Table 3-1. This boiler is a balanced draft, forced circulation, reheat, single furnace boiler. It has four windboxes located along the four corners of the furnace. There are a total of 20 coal burners, five per corner. The boiler serves a 348 MW steam turbine generator and is equipped with two 50-per-cent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

3.1.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the coal-fired tangential boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.45 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Anhydrous ammonia is utilized as a reagent for the SCR system.

- The system is designed for an ammonia slip of 5 ppm.

- A 14-day storage is provided at the plant site for anhydrous ammonia. This storage capacity is based on a full-load operation of the boiler.

- It is assumed that the existing plant setting allows installation of the SCR reactors between the economizer and air heater without a need to relocate any major structure or equipment.

- The operating life of the SCR catalyst is assumed at 3 years. A catalyst life management strategy is not used for this evaluation. It is also assumed that no appreciable difference in the catalyst life occurs when the plant is operated at low capacity factors. This assumption results in conservative cost estimates, since it is expected that a low-capacity factor may result in a net catalyst life increase.

- Other general SCR system design details, assumptions, and impacts on the existing equipment outlined in Appendix A (Section 4.5 of Appendix B) also apply to this case.

The SCR technology is a postcombustion technology, in which the reagent is injected into the flue gas stream at the economizer outlet upstream of the catalyst reactor. As such, SCR technology has no direct impact on the boiler performance. The boiler parameters shown in Table 3-1 would remain unchanged following a SCR retrofit. However, such a retrofit would impact

Injection of the urea solution within the boiler does have an impact on the boiler performance, because of the heat loss associated with the moisture content of this solution. This heat loss causes a slight reduction in the boiler efficiency, resulting in increased fuel flow, ash generation, and combustion air and flue gas flow rates. The overall impacts of the SNCR system retrofit on the study boiler are as follows:

- The boiler efficiency reduces from 88.39 to 88.09 percent. The boiler heat input increases from 3,210 to 3,244 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 157 kW.

- The urea consumption requirement for the SNCR system is 350 gal./hr.

- The water consumption requirement for the SNCR system is 4,470 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (33 to 952 MW) of tangential, coal-fired boilers. As shown in Figure 3-6, the capital costs range from approximately $6 to $46/kW. The levelized costs at a capacity factor of 65 percent range from 1.13 to 2.15 mils/kWh and $1,140 to $2,130/ton NO_x removed (Figures 3-7 and 3-8). The levelized costs at a capacity factor of 27 percent range from 1.32 to 3.78 mils/kWh and $1,330 to $3,800/ton NOx removed (Figures 3-9 and 3-10).

3.2 Wall-Fired Boiler Applications

The NO_x control technologies evaluated for this boiler type include SCR and SNCR. The design data for the representative boiler selected for this evaluation are shown in Table 3-1. This boiler is a balanced draft, natural circulation, reheat, single furnace boiler. It has 24 burners located four high and six wide on the front wall of the unit. The boiler serves a 381 MW steam turbine generator and is equipped with two 50-percent-capacity forced draft fans, two 50-percent-capacity induced draft fans, and an electrostatic precipitator for removing dust from the flue gases exiting the boiler.

3.2.1 SCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SCR technology for the wall-fired boilers:

- The SCR system is designed to reduce NO_x emission from a baseline level of 0.5 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.1 apply equally to this case.

The consumables associated with the SCR system retrofit for the study boiler are as follows:

Auxiliary power consumption	842 kW
Anhydrous ammonia consumption	476 lb/hr
Average catalyst replacement	5417 ft³/yr

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (30 to 1,300 MW) of wall-fired boilers. As shown in Figure 3-11, the capital costs range from approximately $37 to $134/kW. The levelized costs at a capacity factor of 65 percent range from 2.03 to 4.5 mils/kWh and $1,180 to $2,600/ton NO_x removed (Figures 3-12 and 3-13). The levelized costs at a capacity factor of 27 percent range from 4.5 to 10.4 mils/kWh and $2,700 to $6,100/ton NO_x removed (Figures 3-14 and 3-15).

3.2.2 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the wall-fired boilers:

- The SNCR system is designed to provide a 50 percent NO_x reduction from a baseline NO_x rate of 0.50 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit on the study boiler are as follows (refer to Table 3-1):

- The boiler efficiency reduces from ~~88.38~~ *88.4* to ~~87.96~~ *88.0* percent. The boiler heat input increases from 3,600 to 3,618 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 193 kW.

- The urea consumption requirement for the SNCR system is 433 gal./hr.

- The water consumption requirement for the SNCR system is 5,570 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for the entire size range (30 to 1,300 MW) of wall-fired boilers. As shown in Figure 3-16, the capital costs range from approximately $6.5 to $52/kW. The levelized costs at a capacity factor of 65 percent range from 1.18 to 2.32 mils/kWh and $980 to $1,920/ton NO_x removed (Figures 3-17 and 3-18). The levelized costs at a capacity

TABLE 3-1

ORIGINAL DESIGN DATA
TANGENTIAL AND WALL-BURNER COAL-FIRED BOILERS

Parameter[1]	Tangential Boiler[2]	Wall-Fired Boiler[2]
Boiler size, MW	348	381
Boiler load, % MCR	100	100
Boiler type	Reheat	Reheat
Heat input, MMBtu/hr	3,210	3,600
Fuel consumption, ton/hr	127	142
Solid waste, ton/hr	9.82	10.98
Boiler efficiency, %	88.39	88.39
Fuel analysis (wt. %):		
Ash	7.7	7.7
Moisture	8.4	8.4
Sulfur	0.8	0.8
HHV, Btu/lb	12,696	12,696

NOTES

1. Only data pertinent to the NO_x control technologies are shown.

2. The same coal is fired in both boilers. It is assumed that efficiency is the same for both boiler types. In practice, there may be a small difference in the efficiencies; however, the difference would be insignificant as long as the operating parameters, such as excess air levels, are the same.

TABLE 3-7

NO$_x$ REDUCTION PERFORMANCE OF COMBUSTION CONTROLS ON VERTICALLY-FIRED BOILERS [32,33,34]

Source	Performance	
	% Reduction	Controlled Emission Rate
AEP Tanner's Creek 1 (152 MWe)	40 (estimated)	0.57 (estimated)
Duquesne Light Elrama Unit 1 (100 MWe)	42	0.45
Duquesne Light Elrama Unit 2 (100 MWe)	≥40	~0.45
Duquesne Light Elrama Unit 3 (125 MWe)	≥40	~0.45

Combustion controls have not yet been applied to wet-bottom boilers in the U.S. However, as shown above, a major utility has announced plans to retrofit a wet-bottom wall-fired boiler in the fall of 1995 with combustion controls, specifically a two-level overfire air (OFA) system. According to the utility's engineering estimates, the two-level OFA system will achieve an overall 50 percent reduction from uncontrolled levels and will allow the wet-bottom boiler to have a NO$_x$ emission rate of 0.675 lb/MMBtu.

3.2.6.4   Impacts on Boiler Operation. The staged combustion approach has the potential to change the UBC, CO, excess air, and furnace exit gas temperature relative to pre-retrofit levels; thereby potentially affecting boiler combustion efficiency and plant economics. Presented below is information on the possible variation of these parameters.

UBC, CO, and Excess Air [33]

Post-retrofit results from Elrama Unit 2 indicate that UBC levels decreased across the load range. Although some of this decrease may be due to elimination of boiler casing in-leaks, still the results indicate that the retrofit had no negative impacts on UBC. Post retrofit results also indicate that post-retrofit CO levels were maintained at or below 100 ppmv across the load range.

At the Elrama retrofits, the pre- and post-retrofit excess air levels remained relatively constant. No data are currently available on CO, UBC, and excess air changes from the American Electric Power retrofits.

Using the above parameters and the costing methodology described in Appendix A. both the capital and levelized costs have been calculated for a boiler size range of 30 to 1.300 MW. As shown in Figure 4-1, the capital costs range from approximately $14 to $54/kW. The levelized costs at a capacity factor of 65 percent range from 0.55 to 1.5 mils/kWh and $1,350 to $3,750/ton NO_x removed (Figures 4-2 and 4-3). The levelized costs at a capacity factor of 27 percent range from 1.15 to 3.44 mils/kWh and $2,900 to $8,600/ton NO_x removed (Figures 4-4 and 4-5).

4.2 Gas Reburning Evaluation

The following major criteria and assumptions have been followed in evaluating the gas reburning technology for the gas-fired boilers:

- The gas reburn system is designed to reduce the baseline NO_x of 0.25 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- It is assumed that natural gas supply is available at the plant fence for both boilers.

- The reburn system design is based on a 25 percent heat input for the reburn injectors. Natural gas is injected into the furnace along with gas recirculation (system designed for a 10 percent recirculation rate). It is assumed that existing gas recirculation fans will be used for this purpose. The overfire air system is designed for 20 percent of the full-load combustion air requirement for the boiler.

- It is assumed that sufficient space is available in the boilers to add the reburn injectors and overfire air ports. It is also assumed that the available space allows for an adequate residence time for completing the combustion process for the reburn fuel. Lack of an adequate residence time may reduce the effectiveness of the gas reburn system or it may adversely affect the feasibility of installing such a system.

- In some cases, capital cost of the reburn technology application may be lower for a tangential boiler than for a wall-fired boiler. Because of the corner firing arrangement for the tangential boiler, a potential may exist for effectively utilizing a smaller number of reburn injectors. However, any cost difference is not expected to be significant. Therefore, for conservatism, the same capital costs developed for the wall-fired boiler have been used for the tangential boiler.

- Other general gas reburn system design details, assumptions, and impacts on the existing equipment outlined in Appendix A (Section 4.3 of Appendix B) also apply to this case.

Reburn technology has a minimal impact on the performance of a gas-fired boiler. This application involves withdrawal of a portion of the boiler fuel from the main combustion zone and injection of this fuel above the top-most burners. Overfire air is injected further up in the furnace to complete combustion of the reburn fuel. As long as the conditions permit proper combustion of the reburn fuel, the boiler performance would not be affected. Operation of the reburn system does result in an increased auxiliary power consumption (associated with the operation of the gas recirculation fan). In the case of the study boilers, this increase is estimated at 176 MW.

kW?

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 4-6, the capital costs range from approximately $10 to $37/kW. The levelized costs at a capacity factor of 65 percent range from 0.28 to 0.95 mils/kWh and $700 to $2,400/ton NO_x removed (Figures 4-7 and 4-8). The levelized costs at a capacity factor of 27 percent range from 1.32 to 3.78 mils/kWh and $1,330 to $3,800/ton NO_x removed (Figures 4-9 and 4-10).

4.3 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the gas-fired boilers:

- The SNCR system is designed to reduce the baseline NO_x of 0.25 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- A reagent ratio of 1.5 commensurate with the NO_x reduction requirement is used.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit on the study boilers are as follows (refer to Table 4-1):

- The boiler efficiency reduces from 85.65 to 85.48 percent. The boiler heat input increases from 2,980 to 2,986 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in a direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 80 kW.

- The urea consumption requirement for the SNCR system is 155 gal./hr.

- The water consumption requirement for the SNCR system is 1,980 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 4-11, the capital costs range from approximately $3.2 to $28/kW. The levelized costs at a capacity factor of 65 percent range from 0.5 to 1.1 mils/kWh and $1,220 to $2,800/ton NO_x removed (Figures 4-12 and 4-13). The levelized costs at a capacity factor of 27 percent range from 0.6 to 2.1 mils/kWh and $1,520 to $5,200/ton NO_x removed (Figures 4-14 and 4-15).

TABLE 4-1

ORIGINAL DESIGN DATA
TANGENTIAL AND WALL-BURNER TYPE
GAS- AND OIL-FIRED BOILERS

Parameter[1]	Gas-Fired Boilers[2]	Oil-Fired Boilers[2]
Boiler size, MW	350	350
Boiler load, % MCR	100	100
Boiler type	Reheat	Reheat
Heat input, MMBtu/hr	2,980	2,895
Fuel consumption, ton/hr	64.1	79.5
Solid waste, lb/hr	0	303
Boiler efficiency, %	85.65	88.15
Fuel analysis (wt. %):	Natural Gas	No. 6 Oil
Ash		0.1
Moisture		0.1
Sulfur		1.0
HHV, Btu/lb		18,200
CH_4	85.45	
C_3H_8	2.45	
C_2H_6	6.61	
HHV, Btu/ft^3	1,075	

NOTES

1. Only data pertinent to the NO_x control technologies are shown.

2. For each fuel, the same design data apply to both the tangential and wall-fired boilers. It is assumed that efficiency is the same for both boiler types. In practice, there may be a small difference in the efficiencies; however, the difference would be insignificant as long as the operating parameters, such as excess air levels, are the same.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-1, the capital costs range from approximately $21 to $77/kW. The levelized costs at a capacity factor of 65 percent range from 0.87 to 2.27 mils/kWh and $1,500 to $3,800/ton NO_x removed (Figures 5-2 and 5-3). The levelized costs at a capacity factor of 27 percent range from 1.95 to 5.3 mils/kWh and $3,200 to $8,800/ton NO_x removed (Figures 5-4 and 5-5).

5.2 Gas Reburning Evaluation

The following major criteria and assumptions have been followed in evaluating the gas reburning technology for the oil-fired boilers:

- The gas reburn system is designed to reduce the baseline NO_x of 0.3 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- Other criteria and assumptions outlined in Section 4.2 also apply to this case.

The performance impacts of the reburn technology on the oil-fired boilers are as follows:

- The boiler performance changes, because with the reburn system 20 percent of the heat input is by natural gas and 80 percent is by oil. The boiler efficiency reduces from 88.15 to 87.38 percent. The levelized cost estimates must take into account the cost increases incurred in firing natural gas rather than No. 6 oil.

- Firing of natural gas reduces the amount of ash generation by 58 lb/hr and SO_2 emission rate by 620 lb/hr. Both of these reductions benefit the operating costs.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-6, the capital costs range from approximately $12 to $44/kW. The levelized costs at a capacity factor of 65 percent range from 0.8 to 1.6 mils/kWh and $1,350 to $2,650/ton NO_x removed (Figures 5-7 and 5-8). The levelized costs at a capacity factor of 27 percent range from 1.2 to 3.1 mils/kWh and $2,000 to $5,200/ton NO_x removed (Figures 5-9 and 5-10).

5.3 SNCR Evaluation

The following major criteria and assumptions have been followed in evaluating the SNCR technology for the oil-fired boilers:

- The SNCR system is designed to reduce the baseline NO_x of 0.3 lb/MMBtu to the required limit of 0.15 lb/MMBtu.

- All of the other criteria and assumptions described in Section 3.1.2 also apply equally to this case.

The impacts of the SNCR technology retrofit to the study boilers are as follows (refer to Table 4-1):

- The boiler efficiency reduces from 88.15 to 87.88 percent. The boiler heat input increases from 2,895 to 2,904 MMBtu/hr. The fuel flow, ash generation rate, and combustion and flue gas flow rates increase in direct proportion to the change in the heat input.

- There is an overall increase in the plant auxiliary power consumption due to the SNCR equipment as well as the increased demand on the draft fans to accommodate the higher air and flue gas flow rates. The estimated auxiliary power increase is 115 kW.

- The urea consumption requirement for the SNCR system is 210 gal./hr.

- The water consumption requirement for the SNCR system is 2,690 gal./hr.

Using the above parameters and the costing methodology described in Appendix A, both the capital and levelized costs have been calculated for a boiler size range of 30 to 1,300 MW. As shown in Figure 5-11, the capital costs range from approximately $4.0 to $32/kW. The levelized costs at a capacity factor of 65 percent range from 0.65 to 1.35 mils/kWh and $1,100 to $2,300/ton NO_x removed (Figures 5-12 and 5-13). The levelized costs at a capacity factor of 27 percent range from 0.8 to 2.46 mils/kWh and $1,350 to $4,100/ton NO_x removed (Figures 5-14 and 5-15).

TABLE 4-1

FACTORS FOR INDIRECT COSTS(1)

COST ITEM	COMBUSTION CONTROLS	COAL REBURNING	GAS REBURNING	SNCR	SCR
General Facilities	0.0	5.0	2.0	5.0	5.0
Engineering[2]	10.0	10.0	10.0	10.0	10.0
Project Contingency	15.0	15.0	15.0	15.0	15.0
Process Contingency	5.0	5.0	5.0	5.0	5.0
Royalty Allowance	0.0	0.0	0.0	0.0	0.0
Pre-production Cost	2.0	2.0	2.0	2.0	2.0
Inventory Capital	0.0	0.0	0.0	(3)	(3)
Initial Catalyst/Chemicals[4]	0.0	0.0	0.0	0.0	0.0
Allowance for Funds During Construction (AFDUC)[4]	0.0	0.0	0.0	0.0	0.0

NOTES

1. The indirect costs are listed as a percentage of direct capital and other costs. (Refer to Appendix B for further explanation.)

2. Where the capital costs differed significantly between the two boilers evaluated for each technology, the engineering cost factor was modified to compensate for this difference. (Refer to Appendix B for details.)

3. The inventory capital represents the cost of a 14-day storage at full-load demand of urea and anhydrous ammonia for the SNCR and SCR systems, respectively.

4. For all technologies, the royalties and initial catalyst and chemicals are considered part of the direct capital costs. The AFDUC is assumed to be negligible, because of a relatively short construction schedule for all technologies.

A 4-9 X

X

bed design [7]. An additional categorization of these boilers is based on operation at atmospheric or pressurized conditions. An atmospheric FBC (AFBC) system is similar to a pulverized coal-fired boiler in that the furnace operates at close to atmospheric pressure and depends upon heat transfer of a working fluid (water) to recover the heat released during combustion [1]. Pressurized FBC (PFBC) operates at elevated pressures and recovers energy through both heat transfer to a working fluid (water) and the use of the pressurized gas to power a gas turbine [1]; this pressurized design approach also can be classified as a combined power cycle.

2.3   Characterization of Group 2 Boilers

Table 2-1 lists the Group 2 boiler types with respect to population, nameplate capacity, size and estimated uncontrolled NO_x emissions. This table has been developed using information on the boilers in the EPA Group 2 Boiler Database (Appendix A).

Table 2-1. Characterization of Group 2 Boilers

Boiler Type	Population		Nameplate Capacity		Size Mean	Range	Estimated Uncontrolled NO_x	
	(Units)	(%)	(MWe)	(%)	(MWe)	(MWe)	(Tpy)	(%)
Cyclone-Fired	89	39.9	27,562	40.9	310	33-1150	732,300	40.7
Cell-burner Fired	36	16.1	24,572	36.4	683	82-1300	682,000	37.9
Wet-bottom[1]	39	17.5	8,626	12.8	221	29-544	277,000	15.4
Dry-Bottom Vertically-Fired	33	14.8	4,779	7.1	145	35-254	99,700	5.6
Stoker-Fired	21	9.4	1,083	1.6	52	32-79	3,400	0.2
FBC	5	2.3	814	1.2	163	114-194	3,900	0.2
Total	223	100	67,436	100			1,798,304	100

---

[1] NO_x controls for wet bottom boilers of any firing design have to be designed to not disturb slag tapping capability.

TABLE 3-1

SUMMARY OF GROUP 2 BOILER/NO$_x$ CONTROL TECHNOLOGY
DEMONSTRATIONS AND COMMERCIAL RETROFITS

Group 2 Boiler Types	Selected NO$_x$ Control Technologies	Number of Full-Scale or Commercial Retrofits	Retrofit Size Range (MWe)
Boilers with Cell Burners	Plug-in Combustion Controls	7	555 - 780
	Non Plug-in Combustion Controls	3	630 - 760
Cyclone-Fired Boilers	Coal Reburning	1	110
	Natural Gas Reburning	2	33 - 114
	SNCR	1	138
	SCR	1	320
Wet-bottom Boilers	SNCR	1	320
	SCR	1	80 (321)[1]
	Combustion Controls	1	217
Dry-bottom, Vertically-Fired Boilers	SNCR	1	100
	Combustion Controls	4	100-152

X

[1] SCR system was installed only in one of four ducts of the 321 MWe boiler, and only one quarter of the total unit's flue gas volume passes through the SCR system (equivalent to 80 MWe).

missing

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TABLE 3-2

NO$_x$ CONTROL PERFORMANCE FOR CELL BURNER RETROFITS

Low-NO$_x$ Burner Retrofit Project	Load, MWe or % MCR Pre/Post Retrofit	Average Baseline NO$_x$ Emissions lb/MMBtu	Average Post-retrofit NO$_x$ Emissions lb/MMBtu	Avg. NO$_x$ Emissions Reduction %
J. M. Stuart Station Unit #4	-/605	1.16	0.53	55
	-/460	N/A	N/A	54
	-/350	N/A	N/A	48
W. H. Sammis Power Station, Unit #6	627/630	1.15 - 1.40	0.43 - 0.48[2]	58-69
	362/377	0.49	0.31	37
Four Corners Steam Electric Station Unit #4;	100%	1.15	0.49	58
Muskingum River Unit #5	600/607	1.2	0.59	51
	-/454		0.53	
	-/368		0.51	
Hatfield's Ferry Unit #2	555	1.17	0.58	50
Monroe Unit #1[3]	730 (93. 6%)	0.93	0.52	44

Nominal test results achieved during a 61 hour test period one year after retrofit with low-NO$_x$ burners

Data for a performance at full load were not available.

footnotes ? 2 + 3 . Where is 1 ?

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the existing cyclone units can be successfully retrofitted by the coal reburning technology, except for the small, single wall-fired units less than 80 MWe; these units, which represent less than 7% of the cyclone population, lack sufficient furnace height to provide adequate gas residence time.

    3.2.2.2   Applications and Demonstration . There has been one coal-reburning demonstration project on a coal-fired cyclone boiler in the U.S. This is the long-term, U.S. DOE Clean Coal Program demonstration project at **Wisconsin Power and Light Company's Nelson Dewey Station, Unit #2.** The Babcock & Wilcox Company's (B&W's) coal-reburning system was installed on the 110 Mwe cyclone-fired boiler. The demonstration project included three steps: 1)mathematical simulation using B&W in-house models, 2) tests on B&W's Small Boiler Simulator (SBS), and 3)installation and testing on the 110 MWe boiler using two types of coal - Lamar bituminous coal and Powder River Basin (PRB) subbituminous coal. Pertinent project information and data were collected from reference [11].

    3.2.2.3   NO$_x$ Reduction Performance. As discussed in Appendix C, given sufficient time in the reburn zone, reburn zone stoichiometry is the critical parameter that influences NO$_x$ reduction. However, reburn zone stoichiometry is directly related to the percentage of reburn heat input (or the fuel split between the cyclones and reburn burners). In general, an increase in the reburn heat input and commensurate decrease in cyclone heat input will decrease the stoichiometry in the reburn zone and improve NO$_x$ reduction efficiency. Although not readily apparent, this fuel split parameter is constrained in a number of ways, viz.,: 1) diminished flame stability in the reburn zone due to insufficient oxygen concentration, 2) minimum cyclone coal flow rates that must be maintained to control slag tapping, 3) potential for increased boiler tube corrosion within the reburn zone, and 4) increased fly ash load in the furnace which may increase UBC and cause fouling of heat exchange surfaces. These limitations will vary with load, coal type, and unit-specific design. Due to these considerations, NO$_x$ reductions achieved using coal reburning in cyclone boilers will, in general, be dependent on cyclone load and fuel split between cyclones and reburn injectors (or burners).

    As discussed in Appendix C, average NO$_x$ reductions at Nelson Dewey retrofit ranged between 52.4 % (full load) and 33.3% (33% of load) for Lamar bituminous and 55.4% (full load) to 52.6% (55% of load) for PRB subbituminous coals. In general, as per the vendor of this technology, "nominal 50 to 60% reductions can be expected from existing cyclone-equipped boilers."[10].

    Based on ~~this~~ *these* data, a range of 40% to 60% NO$_x$ reduction is recommended for cost sensitivity analyses.

SNCR process is capable of load following through adjustment of Normalized Stoichiometric Ratio (NSR).

Coal Sulfur Content

As discussed in Appendix C, ammonia slip needs to be controlled in SNCR applications to minimize formation of ammonium salts and subsequent boiler impacts. An "acceptable" value of NH_3 slip will probably be a balance of optimum NO_x reduction performance and minimum sulfate/bisulfate formation (as determined by the specific application and fuel).

3.2.5   Application of Selective Catalytic Reduction (SCR) to Group 2 Boilers

3.2.5.1   Description of Control Technology . Selective catalytic reduction (SCR) is a post-combustion, dry NO_x control technology which is typically applied after the boiler economizer (hot-side configuration) or after the ESP (cold-side configuration). The SCR process employs a catalyst, which in the presence of ammonia (NH_3) and oxygen (O_2), reduces NO_x to free nitrogen (N_2) and water (H_2O). The reduction reactions are promoted by heterogeneous catalysts and occur at temperatures below 800° F.

3.2.5.2   Demonstrations and Applications. First patented by a U.S. company in 1959, SCR is a proven technology used to significantly reduce NO_x emissions from over 200 sources in the U.S., and over 500 sources worldwide.   Table 3-6 depicts SCR applications, currently operating or planned, on U.S. coal fired boilers. Pilot and demonstration projects in the U.S., as well as extensive experience abroad, suggest that SCR is a commercially viable control technology option for Group 2 boilers.

The following full-scale SCR installations are currently operational at U.S. coal fired boilers:

- **Southern Company Services, demonstration project being conducted at Gulf Power Company's Plant Crist.** The objective is to evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers. The testing program on this project was started in July of 1993 and will be finished in July of 1995.
  was completed by the end

- **US Generating Company's Chambers Works, Carneys Point Station**, where Foster Wheeler Energy Corporation's SCR system was installed on two 140 MWe boilers which fire an Eastern medium-sulfur coal (with up to 2% sulfur and an ash content of 6 to 10%) [29].

- **Public Service Electric & Gas Mercer Generating Station (321 MWe wet-bottom boiler).** At this installation, SCR system has been installed in one of four ducts, and only one quarter of the total unit's flue gas volume passes through the SCR system (equivalent to 80 MWe).

Gas Reburning Applied to Cyclone-Fired Boilers - test results from the demonstration project at Ohio Edison's Niles Station Unit #1 showed insignificant change in precipitator outlet particulate loadings.

SNCR Applied to All Group 2 Boilers - little quantitative experimental data was found in the literature to characterize SNCR's impact on particulate emissions. Generally, SNCR does not increase particulate emissions.

SCR Applied to All Group 2 Boilers - SCR does not impact particulate emissions.

Impact of NO$_x$ Controls on CO$_2$ Emissions

Implementation of NO$_x$ controls on Group 2 boilers can yield simultaneous impacts on CO$_2$ emissions if: 1) boiler thermal efficiency changes so as to alter coal feed, 2) a portion of the baseline coal feed is replaced by a fuel with a different carbon content per unit of heat input (e.g., natural gas), and 3) post-combustion control technology chemical reagents (i.e. urea and cyanuric acid) react to generate CO$_2$. The first is unlikely to have any significant impact on CO$_2$ emissions since, on average, the NO$_x$ control technologies do not have a significant impact on combustion efficiency. The second item characterizes the application of gas reburning, which can displace up to 25% of the baseline boiler coal input with natural gas, thereby yielding about a 10% reduction in CO$_2$ emissions (based on a 1.7 ratio of coal-produced CO$_2$ versus methane-produced CO$_2$. The third item characterizes the application of urea- or cyanuric acid-based SNCR whose chemical reactions produce modest amounts of added CO$_2$.

3.3.1.2   Impact of NO$_x$ Controls on Secondary Air Emissions. Application of the alternative NO$_x$ control technology options may yield changes to baseline quantities of secondary air emissions generated by Group 2 boilers. These secondary air emissions may include **carbon monoxide (CO)**, **nitrous oxide (N$_2$O)**, and **total hydrocarbons (THC)**. Both SCR and SNCR also generate small amounts of **ammonia (NH$_3$)**.

Table 3-9 summarizes the typical baseline and "controlled" emissions of all secondary air pollutants for the Group 2 boiler/technology combinations under consideration. The details on these pollutants can be found in Appendix C. As seen in Table 3-9, all the control technologies result in negligible CO, THC, and, with the exception of SNCR, N$_2$O impacts. Ammonia emissions are maintained at minimal levels.

3.3.2   Impacts on Solid Waste Disposal

In general, the application of the various NO$_x$ control options is not expected to increase or decrease the quantities of solid wastes generated by the Group 2 boiler population. However, the potential exists to change the characteristics of the solid waste thereby impacting its disposal. There are two ways in which this can happen: 1) a significant increase or decrease in the unburned carbon (UBC) in the boiler fly ash and bottom ash and 2)

3.3.4.2   Ancillary Power Requirements. The ancillary power requirements associated with the NO_x control technologies result from the electric power required to operate associated new equipment, such as fans and pumps. Also, as a result of the retrofit, existing plant equipment such as forced draft or induced draft fans, may also cause changes in power consumption due to incremental changes in air- and gas-side pressure drops. Ancillary power requirements are given below for the various NO_x control technologies.

Low-NO_x Cell Burner Replacement

As discussed in Section 3.2, minor changes in fan energy consumption may occur.

Coal Reburning on Cyclone-Fired Boilers

The implementation of reburning on a cyclone-fired boiler results in the addition of new combustion system components and modified operation of existing components. The modified unit, with addition of primary air fan, pulverizer, piping and burners, overfire air system, and flue gas recirculation, must be compared to the original unit with regard to the fan power requirement to transport fuel and air. This will likely vary from unit to unit based on site-specific factors (e.g., availability of an existing FGR system).

Gas Reburning on Cyclone-Fired Boilers

were

X   No data was available in the literature on incremental changes to ancillary power requirements. However, only minor changes would be expected.

SNCR Applications

Energy consumption by the SNCR process is related to pretreatment and injection of ammonia-based reagents and their carrier gas and liquids. Anhydrous ammonia, aqueous ammonia, or a urea solution are injected in liquid form at high pressure to ensure efficient droplet atomization and dispersion. When anhydrous ammonia is used as the reagent (e.g., Thermal DeNO$_x$ installations), the ammonia is stored in liquid form under pressure. This liquid ammonia must be vaporized via energy addition, mixed with a carrier gas (air or steam), and then injected for adequate mixing. The amount of electricity consumed depends on whether the process uses air or steam for carrier gas. If steam is used, less electricity is consumed by fans but the steam which is taken from the plant will reduce turbine output [42]; the specific energy impact will depend on the location in the power cycle from where the steam is withdrawn.

The Thermal DeNO$_x$ process will consume approximately 1.0 to 1.5 kW for each MWth of boiler capacity (or 0.29 to 0.44 kW/MMBtu/h) when using compressed air as the carrier medium [42]. The actual amount of electricity consumed will ultimately depend on the baseline NO_x emissions, the NH_3/NO_x stoichiometry, and the NO_x reduction goal. For steam-assisted ammonia injection, power consumption is reduced to about 0.2 to 0.3 kW/MWth (0.05 to 0.08 kW/MMBtu/h) of boiler capacity. The amount of steam used is about 25 to 75 lb/h/MWth, but use of compressed air is typically more cost-effective.

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APPENDIX AA

EPA GROUP 2 BOILER DATABASE

AUGUST 1995

1.0 PROJECT OVERVIEW

This report presents the results of a study conducted by Bechtel to develop costs for NO_x control technologies for coal-, gas-, and oil-fired boilers. The types of boilers for each fuel along with the size range and baseline NO_x emission rate for each boiler type were identified by the United States Environmental Protection Agency (EPA), as shown in Table 1-1.

The technical and economic evaluations conducted for this study used a consistent methodology to develop costs for various NO_x control technology applications. The costs are therefore comparable between different boiler types and sizes.

1.1 Project Purpose

The primary objectives of this study were to:

- Develop costs for the NO_x control technologies with a capability to reduce NO_x emissions from the baseline NO_x rate to 0.15 lb/MMBtu for each study boiler

- Develop costs for the NO_x control technologies with a capability to provide substantial NO_x emission reductions for the dry-bottom tangential and wall-fired boilers burning coal beyond those required under 40 CFR Part 76

1.2 Major Results

The capital and levelized costs for each technology case are presented in the figures that are included at the end of this report. The major costs from these figures are summarized in the following tables:

- Table 1-2 presents the fixed and variable costs for a 200 MW boiler for each technology application. The variable costs are reported for both the 27 and 65 percent capacity factors. Two types of variable costs have been included: one containing the carrying charges for the capital expenditure and the other without this carrying charge (as reported in EPRI's TAG). In addition, Table 1-2 also provides a mathematical relationship to facilitate estimation of the capital cost for a given boiler size (MW).

- Tables 1-3 and 1-4 present the capital ($/kW) and levelized ($/ton of NO_x removed) costs for two selected sizes of boiler installations for each NO_x control technology (for both 0.15 lb/MMBtu and substantial reduction cases). These costs are reported for both the 27 and 65 percent capacity factors. Also provided are references to the figures from which these costs have been obtained.

1.3 General Approach to Technical and Cost Analyses

The overall approach for both the technical and cost analyses was based primarily on the methodology utilized in a previous Bechtel study that involved evaluation of NO_x control tech-

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nologies for the Group 2 boilers. A copy of the previous study is provided as Appendix A to this report.

The major elements of the project approach and the areas where the approach differs from the previous study are as follows:

- An evaluation of the commercially available NO_x control technologies was made to determine feasibility for meeting the aforementioned project objectives. Table 1-5 lists these technologies along with their NO_x reduction effectiveness and applicability to each study boiler type. The data presented in Table 1-5 were based on published information on a variety of technology applications (References 1 through 17).

Based on the above evaluation, the following technologies are considered in this report:

  - The selective catalytic reduction (SCR) technology was selected for its capability to provide NO_x reduction to the 0.15 lb/MMBtu limit for all study boilers. For the oil- and gas-fired boilers, both the selective noncatalytic reduction (SNCR) and gas reburning technologies were also selected for the same purpose.

  - The SNCR, gas reburning, and coal reburning technologies have been found to have a capability to provide substantial NO_x reduction for the tangential and wall-fired boilers burning coal. Of these, the SNCR technology was selected for evaluation for this project. Costs of gas and coal reburning applications on Group 2 boilers have been examined in detail in the previous Bechtel study (Appendix A).

- The technical and economic evaluations were conducted on representative boiler installations for each boiler category identified for this project. The design data for the representative boiler installations were developed from Bechtel's in-house database.

- Both capital costs ($/kW) and levelized costs (mils/kWh and $/ton NO_x removed) were developed for the applicable boiler size range for each technology application.

- The capital cost estimates were developed by factoring from the 1994 cost data generated in the previous Bechtel study (Appendix A) for each NO_x control technology. The new estimates were not based on detailed major equipment lists, as developed in the previous study. Instead, appropriate scaling factors representing the general industry practice were applied to the existing costs to obtain costs for this project. This method took into consideration the differences in the overall system size and capacity between each technology application for this project and the corresponding application in the previous study.

- All new costs were developed in 1995 dollars. The latest available Chemical Engineering cost index for September 1995 was used to adjust the estimated 1994 costs to 1995.

- The levelized costs were based on the economic factors listed in the 1993 EPRI TAG (Reference 18). They were developed using a constant dollar approach. Other economic assumptions were the same as shown in Appendix A and detailed in Section 2.0.

TABLE 1-1

STUDY BOILERS AND BASELINE NO$_x$ EMISSIONS[1]

Group 1

Group 2

Boiler Type	Size Range, MW	Fuel	Baseline NO$_x$ Rate lb/MMBtu
Dry bottom, wall-fired	30-1300	Coal Gas Oil	0.50 (Title IV limit) 0.25 0.30
Dry bottom, tangentially fired	33-952	Coal Gas Oil	0.45 (Title IV limit) 0.25 0.30
Cell	200-1300	Coal	0.8-1.5 (1.00 average)
Cyclone	25-1200	Coal	0.8-1.9 (1.17 average)
Wet bottom	25-800	Coal	0.7-1.7 (1.13 average)
Dry bottom, vertically fired	25-300	Coal	0.85-1.1 (1.08 average)

NOTE

1. For Group 1 boilers, the baseline NO$_x$ rates are the currently allowable emission limitations under 40 CFR Part 76. For Group 2 boilers, the baseline NO$_x$ rates represent the average uncontrolled NO$_x$ rates, per boiler type, as presented in Appendix A to "Investigation of Performance and Cost of NO$_x$ Controls as Applied to Group 2 Boilers," August 1995, prepared for the U.S. EPA.

TABLE 1-2

CAPITAL AND O&M COSTS[1],[2],[3]

Case[4]	Capital Cost ($)	Fixed Cost for 200 MW	Variable Cost for 200 MW w/o Capital 65% Capacity Factor	Variable Cost for 200 MW (w/o Capital) 27% Capacity Factor	Variable Cost for 200 MW (w/Capital) 65% Capacity Factor	Variable Cost for 200 MW (w/Capital) 27% Capacity Factor
COAL-TANGEN-SCR	$66.824*(200/MW)^{0.35}$	1	1.04	2.2	2.53	5.78
COAL-TANGEN-SNCR	$15.551*(200/MW)^{0.577}$	0.23	0.99	0.99	1.34	1.82
COAL-WALL-SCR	$69.382*(200/MW)^{0.35}$	1.04	1.11	2.33	2.66	6.05
COAL-WALL-SNCR	$17.511*(200/MW)^{0.577}$	0.26	1.02	1.02	1.41	1.95
COAL-CELL-SCR	$69.217*(200/MW)^{0.324}$	1.04	1.35	2.67	2.89	6.38
COAL-CYCLONE-SCR	$69.55*(200/MW)^{0.261}$	1.04	1.38	2.72	2.93	6.44
COAL-WET BOTTOM-SCR	$70.571*(200/MW)^{0.296}$	1.06	1.41	2.76	2.98	6.54
COAL-VERT-FIRED-SCR	$67.067*(200/MW)^{0.391}$	1.01	1.33	2.6	2.83	6.19
GAS-SCR	$27.483*(200/MW)^{0.35}$	0.41	0.17	0.28	0.79	1.75
GAS-REBURN	$19.025*(200/MW)^{0.357}$	0.29	0.03	0.03	0.45	1.04
GAS-SNCR	$9.433*(200/MW)^{0.577}$	0.14	0.42	0.42	0.63	0.92
OIL-SCR	$39.975*(200/MW)^{0.35}$	0.6	0.36	0.7	1.25	2.84
OIL-REBURN	$22.298*(200/MW)0.357$	0.34	0.51	0.51	1.01	1.7
OIL-SNCR	$10.638*(200/MW)^{0.577}$	0.16	0.58	0.58	0.82	1.15

NOTES

1. Fixed costs are reported in $/kW-yr. The variable costs are reported in mil/kWh.
2. The variable costs are reported both with and without the carrying charges for the capital costs. As per the EPRI's TAG, the variable costs do not include carrying charges. Also, for this report, the costs associated with the changes in the fuel consumption rates because of the retrofit have been included in the variable costs. EPRI does not include fuel costs in the variable cost component.
3. The capacity factor reflects the annual usage for which the NO$_x$ control technology is in operation.
4. Where the boiler firing type is not mentioned, the case applies to both the wall-fired and tangentially fired boilers.

2081/60NStudy/Con-Fast-NOx

TABLE 1-3

SUMMARY OF RESULTS
NO$_x$ CONTROL TECHNOLOGIES ACHIEVING 0.15 LB/MMBTU LIMIT

Boiler[1]	Fuel	NO$_x$ Control	Boiler Size, MW	65% Capacity Factor[2] $/kW	$/Ton	27% Capacity Factor[2] $/kW	$/Ton	Figures[3]
TN	Coal	SCR	200	~~66.82~~67	1935	~~66.82~~67	4427	3-1,3,5
			930	39.02	1439	39.02	3238	
WF	Coal	SCR	200	69.38	1670	69.38	3815	3-11,13,15
			1030	39.X	1226	39.X	2748	
CELL	Coal	SCR	200	69.22	801	69.22	1775	3-21,23,25
			1030	~~40.74~~	624	~~40.74~~	1351	
CYC	Coal	SCR	200	~~69.557~~	695	~~69.557~~	1536	3-26,28,30
			1030	45.34	536	45.34	1125	
WB	Coal	SCR	200	~~70.577~~	733	~~70.577~~	1616	3-31,33,35
			730	48.07	572	48.07	1231	
VF	Coal	SCR	70	101.11	907	101.11	2032	3-36,38,40
			200	67.07	750	67.07	1654	

NOTES

1. The legend for the symbols used is:
   - CYC   Cyclone-fired
   - TN   Tangential
   - VF   Vertically fired, dry bottom
   - WF   Wall-fired, dry bottom
   - WB   Wet bottom
2. The capacity factor reflects the annual duration for which the NO$_x$ technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

TABLE 1-3 (Continued)

Boiler[1]	Fuel	NOx Control	Boiler Size, MW	65% Capacity Factor[2]		27% Capacity Factor[2]		Figures[3]
				$/kW	$/Ton	$/kW	$/Ton	
WF, TN	Gas	SCR	200	27.48	2142	27.48	4802	4-1,3,5
			930	16.95	1429	16.95	3091	
WF, TN	Gas	Reburn	200	19.03	1250	19.03	2910	4-6,8,10
			930	10.99 n	748	10.99 n	1706	
WF,TN	Gas	SNCR	200	9.42	1632	9.42	2455	4-11,13.15
			930	3.66 3.7	1272	3.66 3.7	1592	
WF, TN	Oil	SCR	200	39.98 40	2263	39.98 40	5151	5-1,3,5
			930	23.34	1571	23.34	3492	
WF, TN	Oil	Reburn	200	22.30	1776	22.30	3073	5-6,8,10
			930	12.88 13	1384	12.88 13	2122	
WF,TN	Oil	SNCR	200	10.63 11	1407	10.63 11	2026	5-11,13,15
			930	4.38 4.4	1147	4.38 4.4	1402	

NOTES

1. The legend for the symbols used is:

   CYC   Cyclone-fired
   TN   Tangential
   VF   Vertically fired, dry bottom
   WF   Wall-fired, dry bottom
   WB   Wet bottom

2. The capacity factor reflects the annual duration for which the NO_x technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

TABLE B2-2

ECONOMIC FACTORS

Cost Year	November 1990
Useful Life	20 years
Plant Capacity Factor	65%
Carrying Charges	0.115
Levelization Factors	1.0
Maintenance Cost	1.5% (of capital)/year
Electrical Power Cost	$0.05/kWh
Coal Cost: Western Subbituminous	$1.06/MMBtu
Eastern Bituminous	$1.60/MMBtu
Midwestern Bituminous	$1.45/MMBtu
Lignite	$1.58/MMBtu
Natural Gas Cost	$2.68/MMBtu
Ash Disposal Cost	$9.0/ton
Anhydrous Ammonia Cost	$162/ton of dry NH_3
Urea Cost (50% solution)	$0.75/gallon
SCR Catalyst Replacement Cost	$350/ft^3
SCR Catalyst Operating Life	3 years
Operator Cost	$21.00/person hour
Water Cost	$0.0004/gallon
SO_2 Allowance	$150/ton

The maximum continuous rating (MCR) conditions for the boiler consist of a main steam flow of 2,200,000 lb/h, a reheat steam flow of 1,770,000 lb/h, and pressure/temperatures of 2,625 psig/1005 °F/1005 °F.

Eight pulverizers are provided, each supplying coal to the three burners in one cell. Full-load operation can be achieved with one pulverizer offline. The system design is based on a minimum coal fineness of 70 percent through 200 mesh.

Two regenerative type air heaters are provided at the economizer outlet. An electrostatic precipitator (ESP) located downstream of the air heater provides control of particulate emissions. Two half-capacity forced draft (FD) fans deliver combustion air to the boiler. The flue gases from the boiler pass through the ESP and are discharged to the atmosphere through a stack by two half-capacity induced draft (ID) fans.

The 600 MW unit consists of a supercritical, once-through, balanced-draft, double-reheat, single-furnace boiler. The boiler is equipped with 20 burner cells arranged in a two high and five wide, opposed-fired arrangement. Each cell contains two burners.

The MCR conditions for the boiler consist of a main steam flow of 4,050,000 lb/h, a high-pressure reheat steam flow of 3,350,000 lb/h, a low-pressure reheat steam flow of 3,050,000 lb/h, and pressure/temperatures of 3,800 psig/1005 °F/1030 °F/1055 °F.

Five pulverizers are provided, each serving eight burners in four cells. Full-load operation can be supported with four mills. The design coal fineness is 70 percent through 200 mesh.

The boiler backend equipment configuration is similar to the 300 MW boiler. There are two regenerative air heaters, an ESP, two half-capacity FD fans, and two half-capacity ID fans.

3.2 PLUG-IN LOW-NOx BURNER APPLICATIONS

The plug-in burner technology used for this study entails direct replacement of each individual burner in a cell with a new burner. Overfire air (OFA) ports are added above the top-most burner elevation. This technology has the potential for retrofit in both two- and three-cell burner boilers.

The plug-in type burners used in the study can be supplied by most of the major boiler suppliers. One supplier, Babcock and Wilcox (B&W), offers a different plug-in burner design. To date, this design, referred to as the Low-NO$_x$ Cell Burner (LNCB) technology, has been applied only to boilers with two-burner cells.

3.2.4 Levelized Cost Estimates

The capital cost and plant performance impacts identified in this study were used to develop the overall levelized costs for the 300 and 600 MW units. The costs were estimated both in mils/kWh and $/ton of NO_x removed. For the study boilers, the cost components are as follows:

	Mils/kWh		$/ton NO_x	
	300 MW	600 MW	300 MW	600 MW
Coal consumption	0.043	0.043	13.75	11.80
Power consumption	0.007	0.007	2.26	1.87
Ash disposal	0.009	0.009	3.02	2.54
General maintenance	0.034	0.024	10.92	6.60
Capital cost charge	0.260	0.183	83.70	50.63
Total levelized costs	0.353	0.266	113.65	73.44

The scaling methodology defined in Section 2.4 of this appendix was used to extend the above costs to cover the boiler size range in the cell-burner category. Figures B3-4 and B3-5 show the levelized costs in relation to the unit size. As shown for the 200 to 1,300 MW unit size range, the levelized costs vary from approximately 0.42 to 0.195 mils/kWh and $163 to $48/ton of NO_x removed.

3.2.5 Sensitivity Analyses

The sensitivity evaluations were performed by varying the following parameters for the range values shown in parentheses. (Refer to Section 2.5 of this appendix for the methodology.)

- Capital costs ($\pm$ 5 percent)
- Capacity factor (50 - 85 percent)
- NO_x reduction (50 - 65 percent)

Figures B3-6 through B3-11 show the results of these variations on the technology's capital and levelized costs. The results are summarized below:

a. The capital cost variation has a minor impact on the capital and levelized costs.

b. The capacity factor variation has the greatest impact on the levelized costs (both mils/kWh and $/ton of NO_x). There is no impact on the capital cost.

TABLE B3-3 (Continued)

	Original	Modified
Air for Combustion, klb/hr	2,372	2,379
Flue Gas Leaving Boiler, klb/hr	2,564	2,572
Total Solid Waste, klb/hr	25.7	26.3
COAL ANALYSIS:	Eastern Bituminous	

Proximate Analysis, %

Moisture	8.0
Ash	11.5
Fixed Carbon	46.0
Volatile Matter	34.5

Ultimate Analysis, %

Carbon	67.7
Hydrogen	4.3
Nitrogen	1.3
Sulfur	0.7
Ash	11.5
Oxygen	6.5
Moisture	8
HHV, Btu/lb	12,200
Grindability	46

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BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Number of Burners	24	24
Pulverizer Performance	70% through 200 mesh	
Number of Pulverizers	8	8
Burners per Pulverizer	3	3
Average Excess Air, %	20	20
Ignitors	24	24

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TABLE B3-8 (Continued)

	Original	Modified
Air for Combustion, klb/hr	2,372	2,379
Flue Gas Leaving Boiler, klb/hr	2,564	2,572
Total Solid Waste, klb/hr	25.7	26.3

COAL ANALYSIS:	Eastern Bituminous
Proximate Analysis, %	
Moisture	8.0
Ash	11.5
Fixed Carbon	46.0
Volatile Matter	34.5
Ultimate Analysis, %	
Carbon	67.7
Hydrogen	4.3
Nitrogen	1.3
Sulfur	0.7
Ash	11.5
Oxygen	6.5
Moisture	8
HHV, Btu/lb	12,200
Grindability	46

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Number of Burners	24	16
Pulverizer Performance	70% through 200 mesh	
Number of Pulverizers	8	8
Burners per Pulverizer	.3	.2
Average Excess Air, %	20	20

TABLE B3-9 (Continued)

	Original	Modified
Air for Combustion, klb/hr	4,619	4,633
Flue Gas Leaving Boiler, klb/hr	4,993	5,008
Total Solid Waste, klb/hr	50.1	51.3
COAL ANALYSIS:	Eastern Bituminous	
Proximate Analysis, %		
Moisture	8.0	
Ash	11.5	
Fixed Carbon	46.0	
Volatile Matter	34.5	
Ultimate Analysis, %		
Carbon	67.7	
Hydrogen	4.3	
Nitrogen	1.3	
Sulfur	0.7	
Ash	11.5	
Oxygen	6.5	
Moisture	8	
HHV, Btu/lb	12,200	
Grindability	46	

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BURNER CHARACTERISTICS AND NO$_x$ EMISSIONS:	Original	Modified
Number of Burners	40	40
Pulverizer Performance	70% through 200 mesh	
Number of Pulverizers	5	5
Burners per Pulverizer	8	8
Average Excess Air, %	20	20
Ignitors	40	40

- New coal reburn silo, feeder, pulverizer mill with classifier and inerting/clearing system, primary air fan, and seal air fan

- Reburn burners with retractable oil lighters, spark ignitors, scanners, scanner cooling air fans

- OFA ports with flow adjustment dampers and drives

- Piping systems for pulverized coal, scanner air, and oil

- Ductwork for primary air, secondary air, gas recirculation, tempering air, and seal air

- Pulverizer pyrites removal system ·

- Burner management system (BMS) for the pulverizer, reburn burners, and OFA, with an interface to the existing BMS system

- Electrical equipment, including switchgear circuit breaker, step-down transformer, switchgear, and motor control center

- Building enclosure for the silo, feeder, and pulverizer mill

- Platforms and stairways for the access to the new equipment

The above equipment/material quantities vary between the 150 MW and 400 MW units. (Refer to Tables B4-1 and B4-2.) For example, for the 150 MW unit, only one pulverizer mill along with a coal silo, feeder, and primary air fan are required. To accommodate the large reburn fuel use rate for the 400 MW unit, two half-capacity pulverizer mills must be provided. This requires use of two coal silos, feeders, and primary air fans.

For the 150 MW boiler, the coal reburn burners and the OFA ports are installed on the boiler rear wall opposite the cyclones (Figure B4-1). For the 400 MW, the reburn burners and the OFA are installed on both the front and rear walls of the boiler above the cyclones (Figure B4-2).

The following potential scope adder items have been identified for the coal reburn retrofit. (Refer to Section 2.3.1 of this Appendix for definition.)

a. A stand-alone BMS system for the coal reburn equipment with an interface to the existing BMS system was used in this study. For certain applications, it may be necessary to replace the entire existing BMS system to make it workable with the new equipment.

b. One potential impact of the coal reburning retrofit is an increase in the amount of fly ash exiting the boiler. For Nelson Dewey,[8] the inlet ash loading to ESP increased from 1.3 lb/MMBtu for the baseline conditions to 2.52 lb/MMBtu for the post-retrofit conditions. This increase resulted from more of the total ash converting to fly ash.

Despite the ash loading increase, Nelson Dewey did not report any adverse impact on the ESP performance. In fact, the limited testing done showed an improvement in the average ESP outlet emissions. There was no increase in the stack opacity levels. This performance was attributed to an increase in the particle size ~~distribution~~ mean at the ESP inlet.

For the study, it was assumed that coal reburning has no impact on the ESP performance. To cover the potential for such an impact, costs were developed for an extension of the existing ESP surfaces to provide two additional fields. This cost adder item also includes the modifications required to the existing ash handling system to cover the additional ESP fields.

c. For the plants where asbestos-laden insulation exists on the surfaces affected by the coal reburn retrofit, a cost adder item has been shown for the asbestos removal and reinsulation of the affected surfaces.

4.2.2 Performance Impacts

Tables B4-3 and B4-4 present the design and performance ratings of the 150 and 400 MW boilers, respectively. Both the original design and the post-retrofit conditions are shown. The analyses of the coal fired and baseline NO_x emissions are also included. The coal reburning performance is based on the long-term results from Nelson Dewey.[8] The highlights of the data presented are as follows:

a. It is assumed that the low-NO_x retrofit has no impact on the boiler's capability to maintain the original MCR steam flow conditions, including the steam flow rates, temperatures, and pressures.

b. The coal reburning impact on the flue gas temperatures in the boiler backpass and at the air heater outlet is expected to be minimal. These temperatures are, therefore, assumed to be the same for both pre- and post-retrofit situations for the study boilers.

c. The NO_x reduction for both boilers is assumed to be 50 percent. The experience at Nelson Dewey showed reduction efficiencies as high as 60 percent. The long-term operating data for this installation when firing bituminous and western coals showed an average reduction of over 50 percent.

- Existing BMS modifications to incorporate the reburn system

- Platforms and stairways for access to the new equipment

For the 150 MW boiler, the gas injectors and the OFA ports are installed on the boiler rear wall opposite the cyclones (Figure B4-14). For the 400 MW, the reburn injectors and the OFA are installed on both the front and rear walls of the boiler above the cyclones (Figure B4-15).

The following potential scope adder items have been identified for the gas reburn retrofit. (Refer to Section 2.3.1 of this Appendix for definition.)

a. It is assumed that the existing BMS system can be modified to incorporate the reburn system. For certain applications, such a modification may not be technically feasible and a new BMS system may be required.

b. A gas recirculation system exists for both the study boilers. As discussed previously, a gas recirculation system may not be required for the gas reburning technology. However, a cost estimate is provided for the addition of a gas recirculation system for the Group 2 boilers where such a system is not present. This cost adder item includes a gas recirculation fan, dust collector, ductwork, existing ash handling system modifications to serve the dust collector, and other accessories.

c. For the plants where asbestos-laden insulation exists on the surfaces affected by the gas reburn retrofit, a cost adder item has been shown for the asbestos removal and reinsulation of the affected surfaces.

4.3.2 Performance Impacts

Tables B4-8 and B4-9 present the design and performance ratings of the 150 and 400 MW boilers, respectively. Both the original design and the post-retrofit conditions are shown. The analyses of the coal-fired and baseline NO_x emissions are also included. The gas reburning performance is based on the long-term operating results of existing installations.[9-13] The highlights of the data presented are as follows:

a. It is assumed that the low-NO_x retrofit has no impact on the boiler's capability to maintain the original MCR steam flow conditions, including the steam flow rates, temperatures, and pressures.

b. The gas reburning impact on the flue gas temperatures in the boiler backpass and at the air heater outlet is expected to be minimal. These temperatures are, therefore, assumed to be the same for both pre- and post-retrofit situations for the study boilers.

The SNCR technology's effectiveness generally has been tied to the ability to inject the reagent in a proper flue gas temperature zone (1,800 to 2,000 °F for urea). Also, significant NO_x reductions are considered possible only if an appropriate residence time exists in this effective temperature zone. For many boilers, this temperature zone occurs in the area of high-temperature surfaces where limited residence times exist.

Experience form some operating installations now shows that significant NO_x reductions are possible with the reagent injected at temperatures exceeding the above effective temperature zone.[18] The temperatures at the injection points for these installations have been as high as 2,200 to 2,300 °F. These high temperatures allow reagent injection within the furnace.

The critical NOx can be defined as the minimum NOx emission achievable with SNCR for a given set of flue gas conditions. This minimum NOx is a function of the baseline NOx concentration and the flue gas temperature. It can be calculated by assuming that all nitrogen reactions have infinite time to complete with the result that the reaction product species exist in their equilibrium concentrations.

The critical NOx calculations show that at high baseline NOx concentrations significant NOx reductions are still theoretically possible, even though the reagent is injected outside of the effective temperature zone. There is still a need to select this temperature carefully, because the critical NOx emission increases with increasing injection temperatures.

As an example, at a baseline NOx of 900 ppm, the critical NOx emission is approximately 325 ppm at 2,200F injection temperature. This still represents a significant NOx reduction potential, even though it is low in comparison to injection in the effective temperature zone (at 1,900F, the critical NOx is approximately 50 ppm). At an injection temperature of 2,400F, the calculated critical NOx is approximately 600 ppm, which implies a low NOx reduction potential.

In the above example, the reagent can be injected outside of the effective temperature zone at 2,200F with a sizable NOx reduction. At this temperature, concerns regarding ammonia slip are minimized because reagent decomposition to ammonia should not occur until gas temperatures are below 2,200F.

For achieving reasonable NOx reductions, it is necessary that the baseline NOx be relatively high. At a baseline NOx of 500 ppm, the calculated critical NOx is approximately 230 ppm at an injection temperature of 2,200F, which shows a lower NOx reduction potential (54%) compared to the potential (64%) at 900 ppm of baseline NOx.

Since the effective temperature zone residence time is expected to be limited for many Group 2 boilers, the critical NOx phenomenon allows injection of the reagent at a

temperature beyond the effective temperature zone. In practice, this method may not achieve the maximum NOx reduction represented by the critical NOx; however, as experience shows, reasonable NOx reduction efficiencies are possible.

The baseline NO_x levels for typical cyclone boilers range from 0.9 to 1.8 lb/MMBtu.[8] With these high levels, urea can be injected in the furnace to achieve substantial NO_x reductions, even if the required residence times are not available in the effective temperature zone.

The SNCR systems for the study boilers were designed based on this critical NO_x phenomenon. The design and location of the reagent injectors follow the experiences from the above operating installations, especially the one at B. L. England. For the larger boiler, a higher number of injector levels is used. It is assumed that multiple level injection can be used for larger boilers to achieve the same NO_x reduction as for the smaller boilers.

There is a limited SNCR experience with large size boilers. Proper mixing of the reagent with the flue gas would be a concern with these boilers. However, it is felt that with proper flow modeling, injector designs and locations can be selected for a viable SNCR application.

The NO_x reduction efficiency for this study was selected to maintain a maximum ammonia slip of 10 ppm. The source of urea was assumed to be the NO_xOUT reagent commercially supplied by Nalco Fuel Tech. The 10 ppm ammonia slip is selected to minimize concerns regarding adverse impacts of ammonium salts on the boiler backend equipment. The ammonium salts can form via reaction between the unreacted ammonia and sulfur-trioxide present in the flue gas stream.

The results of the SNCR technology evaluations for this study are presented below.

4.4.1 Equipment and Material Modifications

Tables B4-11 and B4-12 list the major new equipment and materials required for retrofitting the SNCR technology for the 150 MW and 400 MW boilers, respectively. These tables also include descriptions of the major modifications required to the existing equipment. The equipment additions and modifications include:

- Urea solution storage tank

- Urea circulation module consisting of pumps, electric heaters, and piping to maintain urea in storage at a proper temperature

- Metering module consisting of urea metering pumps, dilution water pumps, and piping to provide metered flow of urea and dilution water to the injectors

- Urea price ($0.7 - 0.8/gallon)

- NSR (0.8 - 1.0)

Figures B4-36 through B4-45 show the results of these variations on the technology's capital and levelized costs. The results are summarized below:

a. The capital cost variation has a minor impact on the capital and levelized costs.

b. The capacity factor variation has a relatively low impact on the levelized costs (both mils/kWh and $/ton of NO_x). There is no impact on the capital cost.

c. NO_x reduction variation has no impact on the capital cost and levelized cost in mils/kWh. It has the greatest impact on the $/ton of NO_x costs.

d. The urea price variation has a relatively low impact on the levelized costs. The capital costs are not affected.

e. The NSR variation has a significant impact on the levelized costs and no impact on the capital cost.

4.5 SELECTIVE CATALYTIC REDUCTION (SCR) APPLICATIONS

The SCR technology has been applied extensively to fossil boilers. The majority of this experience to date has been on low to medium sulfur fuels. Also, coal-fired installations have generally consisted of pulverized coal (PC) boilers. One installation on a cyclone-fired boiler is at the Merrimack Power Station of Public Service of New Hampshire. The SCR system installed at the 320 MW Unit 2 of this station is used scheduled to complete startup in June 1995.[19]

The design and performance estimates for the SCR system in this study were based on the published data[19-21] and information received from the suppliers.[3, 22, 23] In addition, Bechtel inhouse information from various past studies and three coal-fired SCR installations (two of them operational) was used.

The SCR system design is greatly influenced by site-specific factors, which vary between power plants. In general, the most important factors are common to all types of coal-fired boilers. They include the fuel characteristics, flue gas temperatures, and space available for the SCR reactors. The cyclone boilers do have certain specific features that require consideration in the SCR design. However, the majority of the technology experience on PC boilers is applicable to the cyclone boilers.

Air for Combustion, klb/h	1,152	1,152
Flue Gas Leaving Boiler, klb/h	1,317	1,317
Total Solid Waste, klb/h	12.9	13.1

COAL ANALYSIS: · Midwestern Bituminous

Proximate Analysis, %

Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0

Ultimate Analysis, %

Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900
Grindability	50

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Number of Cyclones	4	4
Number of Reburn Burners/OFA Ports	NA	4
Number of Pulverizers	NA	1
Burners per Pulverizer	NA	4
Average Excess Air, %	16	16
NO_x Emission, lb/MMBtu (100% Load)	1.40	0.70
Increased Auxiliary Power, kW	Base	476

Air for Combustion, klb/h	3,227	3,227
Flue Gas Leaving Boiler, klb/h	3,692	3,692
Total Solid Waste, klb/h	35.9	36.7

COAL ANALYSIS:	Midwestern Bituminous
Proximate Analysis, %	
Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0
Ultimate Analysis, %	
Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900
Grindability	50

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Number of Cyclones	12	12
Number of Reburn Burners/OFA Ports	NA	12
Number of Pulverizers	NA	2
Burners per Pulverizer	NA	6
Average Excess Air, %	16	16
NO_x Emission, lb/MMBtu (100% Load)	1.3	0.65
Increased Auxiliary Power, kW	Base	1,462

Coal Consumption, tons/h	54	44
Air for Combustion, klb/h	1,152	1,148
Flue Gas Leaving Boiler, klb/h	1,317	1,306
Total Solid Waste, klb/h	13	10

COAL ANALYSIS: Midwestern Bituminous

Proximate Analysis, %

Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0

Ultimate Analysis, %

Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900
Grindability	50

Natural Gas Analysis, % by volume

CH4	90
C2H6	5
N2	5
HHV, Btu/scf	1,002

Coal Consumption, tons/h	152	123
Air for Combustion, klb/h	3,227	3,215
Flue Gas Leaving Boiler, klb/h	3,692	3,660
Total Solid Waste, klb/h	36	29

COAL ANALYSIS:	Midwestern Bituminous
Proximate Analysis, %	
Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0
Ultimate Analysis, %	
Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900
Grindability	50
Natural Gas Analysis, % by volume	
CH_4	90
C_2H_6	5
N_2	5
HHV, Btu/scf	1,002

Air for Combustion, klb/h	1,152	1,160
Flue Gas Leaving Boiler, klb/h	1,317	1,351
Total Solid Waste, klb/h	13	13.1

COAL ANALYSIS: Midwestern Bituminous

Proximate Analysis, %

Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0

Ultimate Analysis, %

Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900 Btu/lb
Grindability	50

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Number of Cyclones	4	4
Average Excess Air, %	16	16
NO_x Emission, lb/MMBtu (100% Load)	1.4	0.91
Increased Power Consumption, kW	Base	67

Air for Combustion, klb/h	3,227	3,249
Flue Gas Leaving Boiler, klb/h	3,692	3,779
Total Solid Waste, klb/h	36	36.2

COAL ANALYSIS: Midwestern Bituminous

Proximate Analysis, %

Moisture	5.8
Ash	11.7
Fixed Carbon	44.5
Volatile Matter	38.0

Ultimate Analysis, %

Carbon	66.4
Hydrogen	4.5
Nitrogen	1.3
Sulfur	2.7
Ash	11.7
Oxygen	7.6
Moisture	5.8
HHV, Btu/lb	11,900
Grindability	50

BOILER CHARACTERISTICS AND NO$_x$ EMISSIONS:	Original	Modified
Number of Cyclones	12	12
Average Excess Air, %	16	16
NO$_x$ Emission, lb/MMBtu (100% Load)	1.3	0.85
Increased Power Consumption, kW	Base	205

Air for Combustion, klb/h	800	804
Flue Gas Leaving Boiler, klb/h	860	864
Total Solid Waste, klb/h	6.77	6.8

COAL ANALYSIS:	Eastern Bituminous
Proximate Analysis, %	
Moisture	5.0
Ash	10.0
Fixed Carbon	53.5
Volatile Matter	31.5
Ultimate Analysis, %	
Carbon	71.8
Hydrogen	4.7
Nitrogen	1.2
Sulfur	2.1
Ash	10.0
Oxygen	5.2
Moisture	5.0
HHV , _Btu/lb_	13,100

X

BOILER CHARACTERISTICS AND NO$_x$ EMISSIONS:

Average Excess Air, %	22	22
NO$_x$ Emissions, lb/MMBtu (100% Load)	0.95	0.62
Increased Power Consumption, kW	Base	25
Urea Consumption, gal/h	Base	100
Water Consumption, gal/h	Base	1,320

BOILER EFFICIENCY BY HEAT LOSS:

Dry Gas Loss	4.07	4.07

Air for Combustion, klb/h	2,082	2,091
Flue Gas Leaving Boiler, klb/h	2,240	2,250
Total Solid Waste, klb/h	17.95	18.04

COAL ANALYSIS: Eastern Bituminous

Proximate Analysis, %

Moisture	5.0
Ash	10.0
Fixed Carbon	53.5
Volatile Matter	31.5

Ultimate Analysis, %

Carbon	71.8
Hydrogen	4.7
Nitrogen	1.2
Sulfur	2.1
Ash	10.0
Oxygen	5.2
Moisture	5.0
HHV	13,100

BOILER CHARACTERISTICS AND NO$_x$ EMISSIONS:

Average Excess Air, %	20	20
NO$_x$ Emission, lb/MMBtu (100% Load)	0.92	0.60
Increased Power Consumption, kW	Base	109
Urea Consumption, gal/h	Base	260
Water Consumption, gal/h	Base	3,370

BOILER EFFICIENCY BY HEAT LOSS:

Dry Gas Loss	4.00	4.00

Air for Combustion, klb/h	901	907
Flue Gas Leaving Boiler, klb/h	971	977
Total Solid Waste, klb/h	13.6	13.7

COAL ANALYSIS: Eastern Bituminous

Proximate Analysis, %

Moisture	4.5
Ash	15.8
Fixed Carbon	50.5
Volatile Matter	29.2

Ultimate Analysis, %

Carbon	69.3
Hydrogen	4.3
Nitrogen	1.2
Sulfur	0.6
Ash	15.8
Oxygen	4.3
Moisture	4.5
HHV, Btu/lb	12,100

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Average Excess Air, %	15	15
NO_x Emissions, lb/MMBtu (100% Load)	1.20	0.78
Increased Power Consumption, kW	Base	51
Urea Consumption, gal/h	Base	150
Water Consumption, gal/h	Base	1,930

Air for Combustion, klb/h	1,649	1,659
Flue Gas Leaving Boiler, klb/h	1,777	1,788
Total Solid Waste, klb/h	24.9	25.1

COAL ANALYSIS: Eastern Bituminous

Proximate Analysis, %

Moisture	4.5
Ash	15.8
Fixed Carbon	50.5
Volatile Matter	29.2

Ultimate Analysis, %

Carbon	69.3
Hydrogen	4.3
Nitrogen	1.2
Sulfur	0.6
Ash	15.8
Oxygen	4.3
Moisture	4.5
HHV, Btu/lb	12,100

BOILER CHARACTERISTICS AND NO_x EMISSIONS:	Original	Modified
Average Excess Air, %	15	15
NO_x Emissions, lb/MMBtu (100% Load)	1.20	0.78
Increased Power Consumption, kW	Base	95
Urea Consumption, gal/h	Base	275
Water Consumption, gal/h	Base	3,530

TABLE 1-4

SUMMARY OF RESULTS
COST OF SNCR APPLICATIONS ON DRY-BOTTOM WALL- AND TANGENTIALLY FIRED BOILERS

Boiler[1]	Fuel	NO$_x$ Control	Boiler Size, MW	65% Capacity Factor[2]		27% Capacity Factor[2]		Figures[3]
				$/kW	$/Ton	$/kW	$/Ton	
TN	Coal	SNCR	200	15.55	1378	15.55	1921	3-6,8,10
			930	6.4	1150	6.4	1377	
WF	Coal	SNCR	200	17.51	1210	17.51	1720	3-16,18,20
			1030	6.80	988	6.80	1186	

NOTES

1. The legend for the symbols used is:
   - TN   Tangential
   - WF   Wall-fired, dry bottom
2. The capacity factor reflects the annual duration for which the NO$_x$ technology is in operation.
3. The cost data presented are taken from the curves shown in the referenced figures included in this report.

2.0 METHODOLOGY AND GENERAL ASSUMPTIONS

The methodology and assumptions used in selecting the applicable NO_x control technologies and conducting the technical and economic evaluations for this project are detailed in this section.

2.1 Technology Selections

Table 1-2 categorized the commercially available technologies and their NO_x control potential for various boiler types. As shown in this table, the NO_x reduction effectiveness varies depending on the site-specific conditions for any given application.

The study criteria define the baseline NO_x rates for the dry-bottom wall-fired and tangential boilers burning coal to be 0.45 and 0.5 lb/MMBtu, respectively (these rates being required by 40 CFR Part 76). The baseline NO_x rates for the same boilers on oil and gas are defined as 0.3 and 0.25 lb/MMBtu, respectively, because these rates currently are being achieved on gas- and oil-fired boilers. It is assumed that these NO_x rates correspond to boilers equipped with low-NO_x burners only (no overfire air ports).

The above assumption implies that full credit can be taken for the NO_x reduction potential of the technologies (such as gas reburning) utilizing overfire air ports. Without this assumption, application of these technologies to boilers with existing overfire air ports would be possible only if the ports are replaced with the new ports associated with the technologies. Deletion of the existing ports would have a corresponding impact of increasing the baseline NO_x levels, thus requiring a higher NO_x reduction to achieve 0.15 lb/MMBtu.

As per the study criteria, the NO_x reduction efficiencies required to meet the 0.15 lb/MMBtu for the gas- and oil-fired boilers are 40 and 50 percent, respectively. For coal-fired boilers, these efficiencies range from 66.67 to 87.18 percent.

Based on the above background information and assumptions, assessment of the feasibility of applying various technologies to the study boilers is as follows:

- The various components of combustion controls include low-NO_x burners, overfire air ports, and gas recirculation fans. Where applicable, the study boilers are already equipped with low-NO_x burners. Since these burners reflect a major portion of the overall effectiveness of combustion controls, installation of other technology components on these boilers to achieve 0.15 lb/MMBtu does not appear possible.

- The coal reburning technology is not feasible for application on any coal-fired study boiler, since the minimum required NO_x reduction efficiency of 66.67 percent is still higher than the maximum potential of this technology (50 percent reduction).

- The gas reburning technology can provide a NO_x reduction ranging from 40 to 60 percent. Since the reductions to achieve the 0.15 lb/MMBtu level for the gas- and oil-fired boilers fall within this range, this technology is considered to be a suitable candidate for these boilers. It is to be recognized that site-specific factors for some plants may pose serious constraints

APPENDIX AA

LIST OF TABLES

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Table AA-1
Cell Burner Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
ALABAMA	GREENE COUNTY	ALABAMA POWER CO	1	OPPOSED/CELL	DRY	299.20	1965	10.6502270	0.819	CREV
GEORGIA	HARLLEE BRANCH	GEORGIA POWER CO	1	OPPOSED/CELL	DRY	250.00	1965	16.6651360	1.179	CREV
GEORGIA	HARLLEE BRANCH	GEORGIA POWER CO	3	OPPOSED/CELL	DRY	480.70	1968	30.2172470	1.037	CREV
GEORGIA	HARLLEE BRANCH	GEORGIA POWER CO	4	OPPOSED/CELL	DRY	490.00	1969	31.6027730	1.037	CREV
INDIANA	WARRICK	SOUTHERN INDIANA GAS & ELEC CO	4	OPPOSED/CELL	DRY	323.00	1970	14.7474960	1.000	ETS
IOWA	DUBUQUE	INTERSTATE POWER CO	1	OPPOSED/CELL	DRY	37.50	1959	1.6582570	0.689	CREV
IOWA	DUBUQUE	INTERSTATE POWER CO	5	OPPOSED/CELL	DRY	26.75	1952	0.6696860	0.796	CREV
MASSACHUSETTS	BRAYTON POINT	NEW ENGLAND POWER CO	3	OPPOSED/CELL	DRY	642.60	1969	29.4908590	1.300	UARG
MICHIGAN	J H CAMPBELL	CONSUMERS POWER CO	2	OPPOSED/CELL	DRY	385.00	1967	21.6168990	1.000	ETS
MICHIGAN	MONROE	DETROIT EDISON CO	1	OPPOSED/CELL	DRY	817.20	1971	45.4086130	0.855	CREV
MICHIGAN	MONROE	DETROIT EDISON CO	2	OPPOSED/CELL	DRY	822.60	1972	43.4412050	0.855	CREV
MICHIGAN	MONROE	DETROIT EDISON CO	3	OPPOSED/CELL	DRY	822.60	1973	51.5213540	0.779	CREV
MICHIGAN	MONROE	DETROIT EDISON CO	4	OPPOSED/CELL	DRY	817.20	1974	43.6503710	0.779	CREV
MINNESOTA	FOX LAKE	INTERSTATE POWER CO	3	OPPOSED/CELL	DRY	81.60	1962	2.4682880	0.783	CREV
NORTH CAROLINA	BELEWS CREEK	DUKE POWER CO	1	OPPOSED/CELL	DRY	1080.07	1974	39.0053500	1.455	CREV
NORTH CAROLINA	BELEWS CREEK	DUKE POWER CO	2	OPPOSED/CELL	DRY	1080.07	1975	60.3962330	1.364	CREV
OHIO	AVON LAKE	CLEVELAND ELECTRIC ILLUM CO	12	OPPOSED/CELL	DRY	680.00	1970	35.4069970	0.960	ETS
OHIO	CARDINAL	CARDINAL OPERATING COMPANY	1	OPPOSED/CELL	DRY	615.20	1968	25.9145450	0.800	ETS
OHIO	CARDINAL	CARDINAL OPERATING COMPANY	2	OPPOSED/CELL	DRY	615.20	1967	36.2007610	1.020	ETS
OHIO	EASTLAKE	CLEVELAND ELECTRIC ILLUM CO	5	OPPOSED/CELL	DRY	680.00	1972	29.3476360	0.674	CREV
OHIO	GEN J M GAVIN	OHIO POWER CO	1	OPPOSED/CELL	DRY	1300.00	1974	57.0084360	1.160	ETS
OHIO	GEN J M GAVIN	OHIO POWER CO	2	OPPOSED/CELL	DRY	1300.00	1975	71.4697730	1.160	ETS
OHIO	J M STUART	DAYTON POWER & LIGHT CO	1	OPPOSED/CELL	DRY	610.20	1971	38.9768560	1.110	ETS
OHIO	J M STUART	DAYTON POWER & LIGHT CO	2	OPPOSED/CELL	DRY	610.20	1970	36.1570630	1.050	ETS
OHIO	J M STUART	DAYTON POWER & LIGHT CO	3	OPPOSED/CELL	DRY	610.20	1972	36.4387740	0.950	ETS
OHIO	J M STUART	DAYTON POWER & LIGHT CO	4	OPPOSED/CELL	DRY	610.20	1974	40.2369050	1.110	NURF
OHIO	MIAMI FORT	CINCINNATI GAS & ELECTRIC CO	7	OPPOSED/CELL	DRY	557.10	1975	31.3106060	1.070	ETS
OHIO	MUSKINGUM RIVER	OHIO POWER CO	5	OPPOSED/CELL	DRY	615.23	1968	27.3070570	1.097	CREV
OHIO	W H SAMMIS	OHIO EDISON CO	7	OPPOSED/CELL	DRY	623.00	1971	34.8729710	1.060	ETS
PENNSYLVANIA	HATFIELD'S FERRY	WEST PENN POWER CO	1	OPPOSED/CELL	DRY	576.00	1969	34.3041960	0.780	ETS
PENNSYLVANIA	HATFIELD'S FERRY	WEST PENN POWER CO	2	OPPOSED/CELL	DRY	576.00	1970	36.2576510	0.780	ETS
PENNSYLVANIA	HATFIELD'S FERRY	WEST PENN POWER CO	3	OPPOSED/CELL	DRY	576.00	1971	27.5639570	0.800	ETS
TENNESSEE	CUMBERLAND	TENNESSEE VALLEY AUTHORITY	1	OPPOSED/CELL	DRY	1300.00	1972	61.3561630	1.570	ETS
TENNESSEE	CUMBERLAND	TENNESSEE VALLEY AUTHORITY	2	OPPOSED/CELL	DRY	1300.00	1973	49.0925510	1.330	ETS
WEST VIRGINIA	FORT MARTIN	MONONGAHELA POWER CO	2	OPPOSED/CELL	DRY	576.00	1980	34.8464200	1.070	ETS
WEST VIRGINIA	JOHN E AMOS	APPALACHIAN POWER CO	3	OPPOSED/CELL	DRY	1300.00	1973	62.3038020	1.046	CREV

Table A-2
Cyclone Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB01	CYCLONE	WET	125.00	1957	6.5504890	1.327	CREV
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB02	CYCLONE	WET	125.00	1950	6.8700440	1.272	CREV
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB03	CYCLONE	WET	179.52	1960	8.7183550	1.519	CREV
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB04	CYCLONE	WET	187.50	1963	9.8375710	1.482	CREV
ILLINOIS	BALDWIN	ILLINOIS POWER CO	1	CYCLONE	WET	623.05	1970	30.2082700	1.700	ETS
ILLINOIS	BALDWIN	ILLINOIS POWER CO	2	CYCLONE	WET	634.50	1973	33.6716390	1.470	ETS
ILLINOIS	COFFEEN	CENTRAL ILLINOIS PUB SERV CO	01	CYCLONE	WET	388.96	1965	12.7391450	1.260	ETS
ILLINOIS	COFFEEN	CENTRAL ILLINOIS PUB SERV CO	02	CYCLONE	WET	616.50	1972	22.6853900	1.260	ETS
ILLINOIS	DALLMAN	SPRINGFIELD CITY OF (IL)	31	CYCLONE	WET	90.25	1968	4.2457250	0.928	CREV
ILLINOIS	DALLMAN	SPRINGFIELD CITY OF (IL)	32	CYCLONE	WET	90.25	1972	2.9833730	1.118	CREV
ILLINOIS	JOLIET 9	COMMONWEALTH EDISON CO	5	CYCLONE	WET	360.40	1959	3.5967090	0.907	CREV
ILLINOIS	KINCAID	COMMONWEALTH EDISON CO	1	CYCLONE	WET	659.70	1967	24.6687340	1.300	ETS
ILLINOIS	KINCAID	COMMONWEALTH EDISON CO	2	CYCLONE	WET	659.70	1968	29.0791550	1.300	ETS
ILLINOIS	LAKESIDE	SPRINGFIELD CITY OF (IL)	7	CYCLONE	WET	37.50	1961	0.7566660	0.733	CREV
ILLINOIS	LAKESIDE	SPRINGFIELD CITY OF (IL)	8	CYCLONE	WET	37.50	1965	0.5852170	0.733	CREV
ILLINOIS	MARION	SOUTHERN ILLINOIS POWER COOP	1	CYCLONE	WET	33.00	1963	0.3738360	1.320	UARG
ILLINOIS	MARION	SOUTHERN ILLINOIS POWER COOP	2	CYCLONE	WET	33.00	1963	0.4163270	1.320	UARG
ILLINOIS	MARION	SOUTHERN ILLINOIS POWER COOP	3	CYCLONE	WET	33.00	1963	1.3159010	1.320	UARG
ILLINOIS	MARION	SOUTHERN ILLINOIS POWER COPP	4	CYCLONE	WET	173.00	1978	12.1554550	1.320	UARG
ILLINOIS	POWERTON	COMMONWEALTH EDISON CO	51	CYCLONE	WET	892.80	1972	8.5587950	0.915	CREV
ILLINOIS	POWERTON	COMMONWEALTH EDISON CO	52	CYCLONE	WET	892.80	1972	10.4857770	0.915	CREV
ILLINOIS	POWERTON	COMMONWEALTH EDISON CO	61	CYCLONE	WET	892.80	1975	16.1212330	0.915	CREV
ILLINOIS	POWERTON	COMMONWEALTH EDISON CO	62	CYCLONE	WET	892.80	1975	13.3083340	0.915	CREV
ILLINOIS	WAUKEGAN	COMMONWEALTH EDISON CO	17	CYCLONE	WET	121.00	1951	0.4566470	0.807	CREV
ILLINOIS	WILL COUNTY	COMMONWEALTH EDISON CO	1	CYCLONE	WET	187.50	1955	2.5372980	0.894	CREV
ILLINOIS	WILL COUNTY	COMMONWEALTH EDISON CO	2	CYCLONE	WET	183.75	1955	4.5667510	0.871	CREV
INDIANA	BAILLY	NORTHERN INDIANA PUB SERV CO	7	CYCLONE	WET	194.00	1962	11.3507960	1.500	ETS
INDIANA	BAILLY	NORTHERN INDIANA PUB SERV CO	8	CYCLONE	WET	421.60	1968	15.0107830	1.500	ETS
INDIANA	MICHIGAN CITY	NORTHERN INDIANA PUB SERV CO	12	CYCLONE	WET	540.00	1974	25.7690190	1.320	ETS
INDIANA	R M SCHAHFER	NORTHERN INDIANA PUB SERV CO	14	CYCLONE	WET	540.00	1976	13.7693910	1.328	CREV
INDIANA	STATE LINE	COMMONWEALTH EDISON CO IN INC	4	CYCLONE	WET	388.96	1962	6.7045790	0.748	CREV
INDIANA	TANNERS CREEK	INDIANA MICHIGAN POWER CO	U4	CYCLONE	WET	579.70	1964	30.7332060	1.910	ETS
IOWA	GEORGE NEAL	IOWA PUBLIC SERVICE CO	1	CYCLONE	WET	147.05	1964	5.3215280	0.940	ETS
IOWA	MUSCATINE	MUSCATINE CITY OF	8	CYCLONE	WET	75.00	1969	3.0698110	0.978	CREV
IOWA	SUTHERLAND	IOWA ELECTRIC LIGHT & POWER CO	3	CYCLONE	WET	81.60	1961	2.7113180	0.717	CREV
KANSAS	KAW	KANSAS CITY CITY OF	3	CYCLONE	WET	65.28	1962	0.4816790	0.766	CREV
KANSAS	LA CYGNE	KANSAS CITY POWER & LIGHT CO	1	CYCLONE	WET	893.40	1973	29.3693570	1.088	CREV
KANSAS	QUINDARO	KANSAS CITY CITY OF	1	CYCLONE	WET	81.60	1965	3.5499800	0.970	CREV

Table A-2 (Continued)
Cyclone Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (QBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
KENTUCKY	ELMER SMITH	OWENSBORO CITY OF	1	CYCLONE	WET	151.00	1964	8.1617950	1.450	ETS
KENTUCKY	PARADISE	TENNESSEE VALLEY AUTHORITY	1	CYCLONE	WET	704.00	1963	45.1297220	1.833	CREV
KENTUCKY	PARADISE	TENNESSEE VALLEY AUTHORITY	2	CYCLONE	WET	704.00	1963	30.1492820	1.722	CREV
KENTUCKY	PARADISE	TENNESSEE VALLEY AUTHORITY	3	CYCLONE	WET	1150.20	1969	50.4944440	1.940	ETS
MARYLAND	C P CRANE	BALTIMORE GAS & ELECTRIC CO	1	CYCLONE	WET	190.40	1961	8.9415260	1.270	ETS
MARYLAND	C P CRANE	BALTIMORE GAS & ELECTRIC CO	2	CYCLONE	WET	209.44	1962	9.9828680	1.460	ETS
MINNESOTA	ALLEN S KING	NORTHERN STATES POWER CO	1	CYCLONE	WET	598.40	1968	32.1317670	1.222	CREV
MINNESOTA	RIVERSIDE	NORTHERN STATES POWER CO	8	CYCLONE	WET	238.85	1964	12.3620520	0.979	CREV
MISSOURI	ASBURY	EMPIRE DISTRICT ELECTRIC CO	1	CYCLONE	WET	231.55	1970	14.2313340	1.090	ETS
MISSOURI	CHAMOIS	CENTRAL ELECTRIC POWER COOP	2	CYCLONE	WET	44.00	1960	2.4340000	1.233	CREV
MISSOURI	LAKE ROAD	ST JOSEPH LIGHT & POWER CO	6	CYCLONE	WET	90.00	1966	2.3499020	1.144	CREV
MISSOURI	NEW MADRID	ASSOCIATED ELECTRIC COOP INC	1	CYCLONE	WET	600.00	1972	32.4647340	1.470	ETS
MISSOURI	NEW MADRID	ASSOCIATED ELECTRIC COOP INC	2	CYCLONE	WET	600.00	1977	33.3642780	1.320	ETS
MISSOURI	SIBLEY	UTILICORP UNITED INC	1	CYCLONE	WET	55.00	1960	0.9578420	1.190	ETS
MISSOURI	SIBLEY	UTILICORP UNITED INC	2	CYCLONE	WET	50.00	1962	1.5850440	1.190	ETS
MISSOURI	SIBLEY	UTILICORP UNITED INC	3	CYCLONE	WET	418.50	1969	15.0176580	1.190	ETS
MISSOURI	SIOUX	UNION ELECTRIC CO	1	CYCLONE	WET	549.80	1967	19.5632420	1.070	ETS
MISSOURI	SIOUX	UNION ELECTRIC CO	2	CYCLONE	WET	549.80	1968	25.0897970	1.210	ETS
MISSOURI	THOMAS HILL	ASSOCIATED ELECTRIC COOP INC	MB1	CYCLONE	WET	180.00	1966	6.0113280	0.900	ETS
MISSOURI	THOMAS HILL	ASSOCIATED ELECTRIC COOP INC	MB2	CYCLONE	WET	285.00	1969	7.5607320	0.900	ETS
NEBRASKA	SHELDON	NEBRASKA PUBLIC POWER DISTRICT	1	CYCLONE	WET	108.80	1960	6.3003910	0.825	CREV
NEBRASKA	SHELDON	NEBRASKA PUBLIC POWER DISTRICT	2	CYCLONE	WET	119.85	1964	5.2712410	0.828	CREV
NEW HAMPSHIRE	MERRIMACK	PUBLIC SERVICE CO OF NH	1	CYCLONE	WET	113.60	1960	8.7181060	1.170	ETS
NEW HAMPSHIRE	MERRIMACK	PUBLIC SERVICE CO OF NH	2	CYCLONE	WET	345.60	1968	17.6801220	1.960	ETS
NEW JERSEY	B L ENGLAND	ATLANTIC CITY ELECTRIC CO	1	CYCLONE	WET	136.00	1962	6.7533280	0.890	ETS
NEW JERSEY	B L ENGLAND	ATLANTIC CITY ELECTRIC CO	2	CYCLONE	WET	163.20	1964	8.0946150	0.960	ETS
NORTH DAKOTA	COYOTE	MONTANA-DAKOTA UTILITIES CO	B1	CYCLONE	WET	450.00	1981	24.1816990	0.811	CREV
NORTH DAKOTA	LELAND OLDS	BASIN ELECTRIC POWER COOP	2	CYCLONE	WET	440.00	1975	27.8957000	1.034	CREV
NORTH DAKOTA	MILTON R YOUNG	MINNKOTA POWER COOP INC	B1	CYCLONE	WET	257.00	1970	16.6890430	0.811	CREV
NORTH DAKOTA	MILTON R YOUNG	MINNKOTA POWER COOP INC	B2	CYCLONE	WET	477.00	1977	36.6861900	1.046	CREV
OHIO	CONESVILLE	COLUMBUS SOUTHERN POWER CO	1	CYCLONE	WET	148.00	1959	1.7122600	1.040	ETS
OHIO	CONESVILLE	COLUMBUS SOUTHERN POWER CO	2	CYCLONE	WET	136.00	1957	5.4652000	1.040	ETS
OHIO	MUSKINGUM RIVER	OHIO POWER CO	3	CYCLONE	WET	237.50	1957	8.4730910	1.090	CREV
OHIO	MUSKINGUM RIVER	OHIO POWER CO	4	CYCLONE	WET	237.50	1958	10.9051150	1.090	CREV
OHIO	NILES	OHIO EDISON CO	1	CYCLONE	WET	125.00	1953	6.7483510	0.980	ETS
OHIO	NILES	OHIO EDISON CO	2	CYCLONE	WET	125.00	1954	5.8055230	0.930	ETS
SOUTH DAKOTA	BIG STONE	OTTER TAIL POWER CO	1	CYCLONE	WET	456.00	1975	25.6133090	0.808	CREV
TENNESSEE	ALLEN	TENNESSEE VALLEY AUTHORITY	1	CYCLONE	WET	330.00	1958	16.3418090	1.950	ETS

Table A-2 (Continued)

Cyclone Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (QBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
TENNESSEE	ALLEN	TENNESSEE VALLEY AUTHORITY	2	CYCLONE	WET	330.00	1959	11.6489000	1.910	ETS
TENNESSEE	ALLEN	TENNESSEE VALLEY AUTHORITY	3	CYCLONE	WET	330.00	1959	6.8339480	1.870	ETS
WEST VIRGINIA	KAMMER	OHIO POWER CO	1	CYCLONE	WET	237.50	1958	16.4168070	1.340	ETS
WEST VIRGINIA	KAMMER	OHIO POWER CO	2	CYCLONE	WET	237.50	1958	14.8240880	1.340	ETS
WEST VIRGINIA	KAMMER	OHIO POWER CO	3	CYCLONE	WET	237.50	1959	13.9501920	1.340	ETS
WEST VIRGINIA	WILLOW ISLAND	MONONGAHELA POWER CO	2	CYCLONE	WET	163.20	1960	5.9307270	1.284	CREV
WISCONSIN	BAY FRONT	NORTHERN STATES POWER CO	5	CYCLONE	WET	67.00	1949	0.0000000	0.828	CREV
WISCONSIN	EDGEWATER	WISCONSIN POWER & LIGHT CO	3	CYCLONE	WET	66.00	1951	3.3468000	0.770	ETS
WISCONSIN	EDGEWATER	WISCONSIN POWER & LIGHT CO	4	CYCLONE	WET	351.00	1969	18.9814880	1.170	ETS
WISCONSIN	NELSON DEWEY	WISCONSIN POWER & LIGHT CO	1	CYCLONE	WET	113.60	1959	4.7544380	0.690	ETS
WISCONSIN	NELSON DEWEY	WISCONSIN POWER & LIGHT CO	2	CYCLONE	WET	113.60	1962	5.1293390	0.690	ETS
WISCONSIN	ROCK RIVER	WISCONSIN POWER & LIGHT CO	1	CYCLONE	WET	75.00	1953	2.4068960	1.000	UARG
WISCONSIN	ROCK RIVER	WISCONSIN POWER & LIGHT CO	2	CYCLONE	WET	75.00	1955	1.9435030	1.000	UARG

Table A-3
Wet Bottom Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
COLORADO	HAYDEN	COLORADO-UTE ELECTRIC ASSN INC	H1	FRONT	WET	190.00	1965	13.3067590	0.220	NURF
COLORADO	PAWNEE	PUBLIC SERVICE CO OF COLORADO	1	FRONT	WET	500.00	1981	34.1895360	0.955	NURF
FLORIDA	BIG BEND	TAMPA ELECTRIC CO	BB01	OPPOSED/TURBO	WET	445.50	1970	16.4038840	1.260	ETS
FLORIDA	BIG BEND	TAMPA ELECTRIC CO	BB02	OPPOSED/TURBO	WET	445.50	1973	23.7656440	1.260	ETS.
FLORIDA	BIG BEND	TAMPA ELECTRIC CO	BB03	OPPOSED/TURBO	WET	445.50	1976	27.3514490	0.640	ETS
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB05	OPPOSED	WET	239.36	1985	15.0333430	1.263	CREV
FLORIDA	F J GANNON	TAMPA ELECTRIC CO	GB06	OPPOSED	WET	414.00	1967	9.2538380	1.608	CREV
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	1	FRONT	WET	217.26	1954	12.4347740	1.680	ETS
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	2	FRONT	WET	217.26	1955	17.1267610	1.680	ETS
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	3	FRONT	WET	217.26	1955	16.1717330	1.680	ETS
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	4	FRONT	WET	217.26	1955	15.6984550	1.710	ETS
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	5	FRONT	WET	217.26	1955	17.1464240	1.710	ETS
INDIANA	CLIFTY CREEK	INDIANA-KENTUCKY ELECTRIC CORP	6	FRONT	WET	217.26	1956	15.9761690	1.710	ETS
KANSAS	KAW	KANSAS CITY CITY OF	1	FRONT	WET	46.00	1954	0.8045750	0.623	CREV
KENTUCKY	CANE RUN	LOUISVILLE GAS & ELECTRIC CO	4	FRONT	WET	163.20	1962	7.3922350	0.965	CREV
KENTUCKY	MILL CREEK	LOUISVILLE GAS & ELECTRIC CO	3	OPPOSED	WET	462.60	1978	19.2378010	0.594	CREV
KENTUCKY	MILL CREEK	LOUISVILLE GAS & ELECTRIC CO	4	OPPOSED	WET	543.60	1982	32.0244950	0.367	CREV
MICHIGAN	JAMES DE YOUNG	HOLLAND CITY OF	5	FRONT	WET	28.75	1969	1.8080370	0.994	CREV
NEW JERSEY	MERCER	PUBLIC SERVICE ELECTRIC&GAS CO	1	FRONT	WET	326.40	1960	15.4533950	1.354	CREV
NEW JERSEY	MERCER	PUBLIC SERVICE ELECTRIC&GAS CO	2	FRONT	WET	326.40	1961	10.8690100	1.899	CREV
NEW YORK	C R HUNTLEY	NIAGARA MOHAWK POWER CORP	63	ARCH	WET	80.00	1942	6.6464390	0.908	CREV
NEW YORK	C R HUNTLEY	NIAGARA MOHAWK POWER CORP	64	ARCH	WET	80.00	1948	6.8837910	0.908	CREV
NEW YORK	C R HUNTLEY	NIAGARA MOHAWK POWER CORP	65	ARCH	WET	80.00	1953	5.3529740	0.908	CREV
NEW YORK	C R HUNTLEY	NIAGARA MOHAWK POWER CORP	66	ARCH	WET	80.00	1954	6.1400000	0.908	CREV
OHIO	KYGER CREEK	OHIO VALLEY ELECTRIC CORP	1	FRONT	WET	217.26	1955	16.5446340	1.410	ETS
OHIO	KYGER CREEK	OHIO VALLEY ELECTRIC CORP	2	FRONT	WET	217.26	1955	16.8041350	1.410	ETS
OHIO	KYGER CREEK	OHIO VALLEY ELECTRIC CORP	3	FRONT	WET	217.26	1955	15.9875470	1.410	ETS
OHIO	KYGER CREEK	OHIO VALLEY ELECTRIC CORP	4	FRONT	WET	217.26	1955	15.8744420	1.410	ETS
OHIO	KYGER CREEK	OHIO VALLEY ELECTRIC CORP	5	FRONT	WET	217.26	1955	15.3839760	1.410	ETS
OHIO	MUSKINGUM RIVER	OHIO POWER CO	1	FRONT	WET	219.69	1953	9.9537390	1.090	CREV
OHIO	MUSKINGUM RIVER	OHIO POWER CO	2	FRONT	WET	219.69	1954	11.1628340	1.090	CREV
OHIO	R E BURGER	OHIO EDISON CO	1	ROOF	WET	62.50	1944	1.1410640	0.830	ETS
OHIO	R E BURGER	OHIO EDISON CO	2	ROOF	WET	62.50	1944	1.2417790	0.900	ETS
OHIO	R E BURGER	OHIO EDISON CO	3	ROOF	WET	62.50	1947	1.2052110	0.940	ETS
OHIO	R E BURGER	OHIO EDISON CO	4	ROOF	WET	62.50	1947	1.1982330	1.090	ETS
OHIO	R E BURGER	OHIO EDISON CO	5	ROOF	WET	100.00	1950	1.9375720	0.750	ETS,
OHIO	R E BURGER	OHIO EDISON CO	6	ROOF	WET	100.00	1950	2.0177160	0.730	ETS
UTAH	BONANZA	DESERET GENERATION & TRAN COOP	1-1	OPPOSED	WET	400.00	1985	27.0444140	0.550	UARG

1)   Gas temperature at the injection location
2)   Urea/ammonia injection location and injector design
3)   Chemical reagent type and stoichiometry
4)   Uncontrolled NO_x emissions

● **Gas Temperature at the Injection Location**

As mentioned in almost all SNCR technical references, the SNCR process operates optimally over a relatively narrow temperature range with either ammonia- or urea-based reagents. This range is from 1600° F to 1850° F with peak removals nominally occurring at 1750° F. However, data presented in [9] have shown that reagents can be successfully injected in furnace locations with temperatures as high as 2400° F, if the baseline NO_x level is relatively high. This concept, described in some detail in [8,9], opens new options for SNCR implementation on Group 2 boilers, which typically exhibit a furnace exit gas temperature (FEGT) above 2100° F, as well as high boiler outlet NO_x concentrations (> 1 lb/MMBtu). Test data for the three projects mentioned previously are presented in **Table C-10**.

These data confirm the conclusions of ICAC member companies [8,9] regarding the effectiveness of urea injection in flue gas with temperatures higher than 2100° F. However, they also show that NO_x reduction is greater for operation within the optimum temperature range, and the required urea stoichiometry is lower.

● **Urea/Ammonia Injection Location and Injector Technology**

The appropriate choice for SNCR injection location and injector technology will be based on two considerations, namely 1) providing a uniform reagent distribution in the gas flow, and 2) providing a proper time-temperature regime. Test data for 13 large-scale SNCR applications provided in [1] show that the highest efficiency can be achieved by injecting the reagent into the furnace, even if the temperature at the injection location is higher than optimum. It was mentioned in [9] that the lower efficiency that occurs when the injection system is installed in cavities of the convective pass is caused by lower residence time and non-uniform distribution of the reagent. Also, a convective pass injection system is usually more complicated and, accordingly, more costly. Therefore, injection into the furnace is the most common design; both NFT and all three Group 2 boiler applications discussed above have used multi-level in-furnace injection through wall-mounted injectors.

● **Chemical type and stoichiometry**

Either urea or ammonia can be used as the reagent in an SNCR application. Kinetically, one mole of urea will react with two moles of NO_x, while one mole of ammonia will react with one mole of NO_x. Thus, in large boilers, the use of urea instead ammonia may result in lowering the required reagent quantity. Additionally, urea is safer to handle and its use can lead to a lower cost for reagent handling and supply equipment. Urea was used on both NFT process applications at the B.L. England and the Mercer stations. A system designed by NOELL for the Arapahoe station is also

C-39

1.0 INTRODUCTION

This appendix documents detailed results of a study conducted by Bechtel Power Corporation to develop costs associated with various NO_x control technology applications for the coal-fired, Group 2 boilers. For each Group 2 boiler category, one or more applicable NO_x control technologies were studied. The technology selection was provided by the U.S. Environmental Protection Agency (EPA), as discussed in the main report. The Group 2 boilers and the low-NO_x technologies covered in the study are as follows:

a. Cell-Burner Boilers

- Combustion modifications (plug-in low-NO_x burners)

- Combustion modification (non plug-in low-NO_x burners)

b. Cyclone-Fired Boilers

- Coal reburning

- Gas reburning

- Selective non-catalytic reduction (SNCR)

- Selective catalytic reduction (SCR)

c. Wet-Bottom Boilers

- SNCR

d. Vertical-Fired, Dry-Bottom Boilers

- SNCR

The primary objective for this study was to develop costs that accurately represent typical low-NO_x technology retrofit applications for the Group 2 boilers. The costs developed included both capital and levelized costs. To facilitate comparisons between various technology cases, the levelized costs were estimated both in mils per killowatthour (mils/kWh) and dollars per ton ($/ton) of NO_x removed.

The study activities included selection of boilers for each technology application, determination of performance and equipment impacts of the technology retrofits, estimation of capital and levelized costs, and development of cost algorithms to cover the plant size range existing within each boiler category population. In addition,

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May 28, 1996

Mr. Ravi K. Srivastava
U.S. Environmental Protection Agency (6204J)
401 M Street, SW
Washington, DC   20460

Dear Mr. Srivastava:

The Institute of Clean Air Companies, Inc. (ICAC) is pleased to submit the
following comments on the draft report, "Cost Estimates for Selected Applications of NO_x
Control Technologies on Stationary Combustion Boilers," and on appendix to the report,
"Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers." As
you know, ICAC is the national association of companies which supply stationary source
air pollution monitoring and control systems, equipment, and services. Our members
include leading suppliers of selective catalytic and non-catalytic reduction (SCR and
SNCR), and also of low-NO_x burners, reburn systems, and NO_x and ammonia monitoring
systems.

**The report should note that cost effectiveness values (expressed in $/ton
of NO_x removed) will decrease as capacity factors increase above 65 percent.**
Given the likelihood that some sort of trading scheme will accompany tightened NO_x
limits, boiler owners can be expected to install controls on the highest capacity factor
boilers: doing so will spread capital and fixed operating costs over the greatest number of
tons of averted emissions, thus minimizing total costs per ton.

**The report should include calculated SNCR costs for all boiler/fuel
combinations.** While SNCR alone may not be sufficient to reduce NO_x emissions to 0.15
lb/MMBtu in all cases, SNCR may be part of combinations of control technologies which
do.

**The report overestimates initial catalyst charges and catalyst
replacement rates for SCR, and thus overestimates SCR costs.** Actual original
installed catalyst volumes (cubic meters of catalyst per MW of plant capacity) are 20-75%
lower than the volumes used in the report. Improvements in catalyst technology and
experience over time have allowed installation of smaller catalyst volumes.

The report also conservatively assumes total replacement of the catalyst bed every
three years for coal-fired boilers. This assumption inflates actual catalyst replacement
costs by a factor of 1.3 to 3, depending on boiler type, and therefore introduces

unacceptable errors into the cost calculations. Industry experience universally supports a staged addition-replacement strategy for extending catalyst life. No SCR systems on coal-fired boilers will require total catalyst change-out at the end of the guarantee period.

Table 1 gives initial catalyst volumes and catalyst replacement rates for existing high-dust SCR systems on coal-fired boilers, as well as predicted rates given in several commercial bids made by one catalyst supplier. Table 2 contains recommendations by that same catalyst supplier for initial catalyst volumes and average replacement rates.

Specific comments:

p. 2-2, fourth paragraph: SCR systems will not necessarily lead to excessive SO_2 to SO_3 conversion rates; SCR catalysts are available which oxidize less than 1% of the SO_2 to SO_3.

p. 3-2: An average catalyst replacement rate of 4,680 ft^3/yr is high, as noted above.

p. 3-2: An average catalyst replacement rate of 5,417 ft^3/yr is high, as noted above.

p. 4-1: A catalyst operating life of 5 years is low for natural gas service; a life of 8-10 years would be more representative of actual operating experience

Appendix, p. B4-22: other SCR system components not listed are reactor structural support steel and NO_x analyzers and miscellaneous instrumentation

Appendix, p. B4-67, B4-69: 200 feet of ductwork between the air blowers and ammonia injection grid seems high

Appendix, p. B4-68: we question whether two new forced draft fans appropriate to a pressurized unit would be necessary

Appendix, p. B4-70: we question whether two new induced draft fans would be necessary

Appendix, p. B4-72: we question the inclusion of the cost of "draft fans as" as a necessary part of the cost of an SCR system

Appendix, p. C-49: The SCR design NO_x removal efficiency is 47% at Stanton 2, and 53% at Birchwood. The actual removal efficiency is 63% at Logan (formerly Keystone), 59% at Indiantown, and 65% at Merrimack. (Note that the 1999 removal efficiency target at Merrimack on the installation of additional catalyst is 90%.)

Appendix, p. C-55, second paragraph: Designing the SCR system for uniform mixing of ammonia in the flue gas upstream of the reactor helps to achieve low ammonia slip.

Please let us know if you have any questions regarding our comments or wish additional information.

Sincerely,

Michael J. Wax

cc: Perrin Quarles Associates, Inc.
        501 Faulconer Drive, Suite 2-D
        Charlottesville, VA   22903

Table4A-4
Vertically Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
COLORADO	ARAPAHOE	PUBLIC SERVICE CO OF COLORADO	1	VERTICAL	DRY	44.00	1950	2.1823950	0.850	UARG
COLORADO	ARAPAHOE	PUBLIC SERVICE CO OF COLORADO	2	VERTICAL	DRY	44.00	1951	1.9238510	0.850	UARG
COLORADO	ARAPAHOE	PUBLIC SERVICE CO OF COLORADO	3	VERTICAL	DRY	44.00	1951	2.3245480	0.850	UARG
COLORADO	ARAPAHOE	PUBLIC SERVICE CO OF COLORADO	4	VERTICAL	DRY	100.00	1955	5.6034210	1.060	UARG
COLORADO	CHEROKEE	PUBLIC SERVICE CO OF COLORADO	1	VERTICAL	DRY	100.00	1957	7.4214160	1.006	UARG
COLORADO	CHEROKEE	PUBLIC SERVICE CO OF COLORADO	2	VERTICAL	DRY	110.00	1959	6.2873530	1.100	UARG
INDIANA	TANNERS CREEK	INDIANA MICHIGAN POWER CO	U1	VERTICAL	DRY	152.50	1951	6.9099000	1.141	CREV
INDIANA	TANNERS CREEK	INDIANA MICHIGAN POWER CO	U2	VERTICAL	DRY	152.50	1952	6.9750700	1.141	CREV
INDIANA	TANNERS CREEK	INDIANA MICHIGAN POWER CO	U3	VERTICAL	DRY	215.40	1954	8.2409640	1.141	CREV
OHIO	BAY SHORE	TOLEDO EDISON CO	1	VERTICAL	DRY	140.62	1955	8.0714440	1.081	CREV
OHIO	BAY SHORE	TOLEDO EDISON CO	2	VERTICAL	DRY	140.62	1959	8.0672570	1.081	CREV
OHIO	MIAMI FORT	CINCINNATI GAS & ELECTRIC CO	5-1	ROOF	DRY	100.00	1949	0.2064160	0.859	CREV
OHIO	MIAMI FORT	CINCINNATI GAS & ELECTRIC CO	5-2	ROOF	DRY	100.00	1949	0.2064160	0.859	CREV
PENNSYLVANIA	ELRAMA	DUQUESNE LIGHT CO	1	ROOF	DRY	100.00	1952	3.4592260	1.000	UARG
PENNSYLVANIA	ELRAMA	DUQUESNE LIGHT CO	2	ROOF	DRY	100.00	1953	3.3554500	1.000	UARG
PENNSYLVANIA	ELRAMA	DUQUESNE LIGHT CO	3	ROOF	DRY	125.00	1954	4.1995280	1.000	UARG
PENNSYLVANIA	HOLTWOOD	PENNSYLVANIA POWER & LIGHT CO	17	ARCH	DRY	75.00	1954	5.8314960	1.072	CREV
PENNSYLVANIA	SUNBURY	PENNSYLVANIA POWER & LIGHT CO	1A	ARCH	DRY	253.53	1949	2.3458920	1.057	CREV
PENNSYLVANIA	SUNBURY	PENNSYLVANIA POWER & LIGHT CO	1B	ARCH	DRY	253.53	1949	2.3464740	1.057	CREV
PENNSYLVANIA	SUNBURY	PENNSYLVANIA POWER & LIGHT CO	2A	ARCH	DRY	253.53	1949	2.3464740	0.847	CREV
PENNSYLVANIA	SUNBURY	PENNSYLVANIA POWER & LIGHT CO	2B	ARCH	DRY	253.53	1949	2.3464740	0.847	CREV
VIRGINIA	CLINCH RIVER	APPALACHIAN POWER CO	1	ROOF	DRY	237.50	1958	13.2137470	1.335	CREV
VIRGINIA	CLINCH RIVER	APPALACHIAN POWER CO	2	ROOF	DRY	237.50	1958	15.1694070	1.335	CREV
VIRGINIA	CLINCH RIVER	APPALACHIAN POWER CO	3	ROOF	DRY	237.50	1961	12.7258590	1.417	CREV
WEST VIRGINIA	KANAWHA RIVER	APPALACHIAN POWER CO	1	VERTICAL	DRY	219.69	1953	7.0583640	1.231	CREV
WEST VIRGINIA	KANAWHA RIVER	APPALACHIAN POWER CO	2	VERTICAL	DRY	219.69	1953	5.2641650	1.231	CREV
WEST VIRGINIA	PHIL SPORN	CENTRAL OPERATING CO	11	ROOF	DRY	152.50	1949	4.8176170	1.207	CREV
WEST VIRGINIA	PHIL SPORN	CENTRAL OPERATING CO	21	ROOF	DRY	152.50	1950	5.9663940	1.207	CREV
WEST VIRGINIA	PHIL SPORN	CENTRAL OPERATING CO	31	ROOF	DRY	152.50	1951	6.7833270	1.207	CREV
WEST VIRGINIA	PHIL SPORN	CENTRAL OPERATING CO	41	ROOF	DRY	152.50	1952	5.6310440	1.207	CREV
WEST VIRGINIA	RIVESVILLE	MONONGAHELA POWER CO	7	TOP	DRY	35.00	1944	1.1801750	0.840	NURF
WEST VIRGINIA	RIVESVILLE	MONONGAHELA POWER CO	8	TOP	DRY	74.75	1951	3.2031420	0.840	NURF
WEST VIRGINIA	WILLOW ISLAND	MONONGAHELA POWER CO	1	TOP	DRY	50.00	1949	1.7776870	0.881	CREV

Table A-5
Stoker Fired Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
IOWA	PELLA	PELLA CITY OF	6	STOKER/SPR	DRY	38.00	1964	0.3176750	0.496	CREV
IOWA	PELLA	PELLA CITY OF	7	STOKER/SPR	DRY	38.00	1964	0.6465380	0.496	CREV
KENTUCKY	HENDERSON	HENDERSON CITY UTILITY COMM	6	STOKER/SPR	DRY	32.30	1968	0.4825320	0.517	CREV
MICHIGAN	WYANDOTTE	WYANDOTTE MUNICIPAL SERV COMM	5	STOKER/SPR	DRY	73.00	1958	0.9372060	0.400	UARG
MINNESOTA	M L HIBBARD	MINNESOTA POWER & LIGHT CO	3	STOKER/SPR	DRY	35.00	1949	0.5667950	0.400	UARG
MINNESOTA	M L HIBBARD	MINNESOTA POWER & LIGHT CO	4	STOKER/SPR	DRY	37.50	1951	0.3475240	0.400	UARG
MISSOURI	COLUMBIA	COLUMBIA CITY OF	6	STOKER/SPR	DRY	73.50	1957	0.1601240	0.400	UARG
MISSOURI	COLUMBIA	COLUMBIA CITY OF	7	STOKER/SPR	DRY	73.50	1957	0.6072390	0.400	UARG
NEW YORK	HICKLING	NEW YORK STATE ELEC & GAS CORP	1	STOKER/SPR	DRY	37.50	1948	1.6016710	0.377	CREV
NEW YORK	HICKLING	NEW YORK STATE ELEC & GAS CORP	2	STOKER/SPR	DRY	37.50	1948	1.5928490	0.377	CREV
NEW YORK	HICKLING	NEW YORK STATE ELEC & GAS CORP	3	STOKER/SPR	DRY	49.00	1952	1.9472650	0.261	CREV
NEW YORK	HICKLING	NEW YORK STATE ELEC & GAS CORP	4	STOKER/SPR	DRY	49.00	1952	2.2057190	0.261	CREV
NEW YORK	JENNISON	NEW YORK STATE ELEC & GAS CORP	1	STOKER/SPR	DRY	37.50	1945	1.2857800	0.300	CREV
NEW YORK	JENNISON	NEW YORK STATE ELEC & GAS CORP	2	STOKER/SPR	DRY	37.50	1945	1.2298170	0.300	CREV
NEW YORK	JENNISON	NEW YORK STATE ELEC & GAS CORP	3	STOKER/SPR	DRY	37.50	1950	1.3538800	0.286	CREV
NEW YORK	JENNISON	NEW YORK STATE ELEC & GAS CORP	4	STOKER/SPR	DRY	37.50	1950	1.3422850	0.286	CREV
WISCONSIN	BAY FRONT	NORTHERN STATES POWER CO	1	STOKER/SPR	DRY	67.00	1949	1.2999630	0.403	CREV
WISCONSIN	BAY FRONT	NORTHERN STATES POWER CO	2	STOKER/SPR	DRY	67.00	1949	0.0000000	0.400	UARG
WISCONSIN	BAY FRONT	NORTHERN STATES POWER CO	4	STOKER/SPR	DRY	67.00	1949	0.0000000	0.657	CREV
WISCONSIN	MANITOWOC	MANITOWOC CITY OF	6	STOKER/SPR	DRY	79.00	1935	1.0558550	0.314	CREV
WISCONSIN	MANITOWOC	MANITOWOC CITY OF	7	STOKER/SPR	DRY	79.00	1935	0.9341210	0.314	CREV

Table A-6
FBC Boilers

STATE	PLANT	UTILITY	BOILER	FIRING TYPE	BOTTOM TYPE	NAMEPLATE CAPACITY (MWe)	COM DATE	1990 HEAT INPUT (GBtu)	UNCONTROLLED NOx (lb/MMBtu)	Source
COLORADO	NUCLA	COLORADO-UTE ELECTRIC ASSN INC	1	CFB	DRY	113.88	1990	4.7857640	0.170	CREV
KENTUCKY	SHAWNEE	TENNESSEE VALLEY AUTHORITY	10	AFB	DRY	175.00	1956	3.5407200	0.230	ETS
MINNESOTA	BLACK DOG	NORTHERN STATES POWER CO	2	AFB	DRY	137.00	1954	1.1586080	0.258	MODEL
NORTH DAK	R M HESKETT	MONTANA-DAKOTA UTILITIES CO	B2	AFB	DRY	75.00	1963	4.6598200	0.286	CREV
TEXAS	TNP ONE	TEXAS-NEW MEXICO POWER CO	U1	CFB	DRY	194.00	1990	8.1054060	0.169	CREV
TEXAS	TNP ONE	TEXAS-NEW MEXICO POWER CO	U2	CFB	DRY	194.00	1991	0.0000000	0.153	CREV

AA-8

The use of low NO_x retrofits on cell burners could change the burner pressure drop relative to the original boiler operation and, thereby, impact the required forced draft fan power.

Similar to low-NO_x burners used on Group 1 boilers, cell burner retrofits typically have a higher pressure drop than regular burners because of their basic design. However, for some retrofit situations, it may be difficult to observe changes because, in addition to burner replacement, the air distribution system may also be modified. This observation can be supported by comparison of two of the cell burner retrofit projects being cited. The retrofit at J. M. Stuart Station was conducted by replacing all of the existing 24 cell burners with 24 low-NO_x cell burners without significant changes in the boiler's air distribution system. As a result, the average burner pressure drop increased by 2.3 inches H_2O. At the W. H. Sammis Power Station, where the retrofit included significant changes in the air distribution system, the pressure drop from windbox-to-furnace was actually reduced from its original level by 0.64 inches H_2O. No data are currently available for the other projects.

As with Group 1 LNBs, the approach of replacing original equipment cell burners with low-NO_x ~~furnace~~ retrofit burners is likely to increase windbox-to-pressure drop by several inches H_2O based on the Stuart Station results. However, unlike the Sammis Station retrofit, the burner air distribution system is unlikely to be modified for most retrofits of this type, and the distribution system pressure drop should not change. Therefore, based on the limited data available from current retrofit projects, the total windbox-to-furnace pressure drop may increase by up to several inches H_2O. While this increase should be incorporated into the boiler retrofit cost assessment, no quantitative sensitivity analysis is warranted.

C.2.1.2 NO_x Reduction Performance

Table C-2 shows full- and partial-load NO_x reduction performance for all six cell burner retrofit projects previously identified. It is evident from this table that all four low-NO_x plug-in retrofits provide significant NO_x reduction, as compared to baseline operation. For the projects with installation of plug-in retrofits, **the range of NO_x reduction at full load is between 50% and 55%** (since it is not known whether Detroit Edison's Monroe Unit #1 was tested at its nominal full load and whether this unit had a low baseline NO_x level). [Note also that these projects do not include **overfire air.**] For plug-in burners with overfire air the expected NOx reductions are 50-65%. [The **"non plug-in" type retrofits of cell burners has yielded up to 69% NO_x reduction at full load.**] [A smaller percent reduction of 37% was obtained at 60% load, but was most likely due to a relatively low NO_x production level during the pre-retrofit conditions, rather than a result of degradation of retrofitted boiler performance at partial load. Notice that NO_x emissions for the Sammis plant were similar for full and partial loads, although the percent reductions were significantly different.]

Continuous emissions monitoring data collected for J.M. Stuart Unit 4 and Muskingum River Unit 5 show consistent long-term NO_x reductions of 55%.

C-8

Table 1. High-Dust SCR Catalyst Requirements in Units in Service or Designed for Coal-Fired Boilers

Boiler Type	Size (MW)	Commercial Operation	Uncontrolled NO_x Emissions (lb/MMBtu)	Removal Efficiency (%)	Initial Catalyst Volume (m³/MW)	Annualized Catalyst Replacement
dry bottom	75	1983	0.23	65	1.00	13%
dry bottom	410	1988	0.51	69	1.86	6%
dry bottom	750	1989	0.61	75	1.05	5%
dry bottom	700	1989	0.36	73	0.96	11%
dry bottom	350	1989	0.75	79	1.21	10%
dry bottom	500	1991	0.29	67	0.83	<8%
dry bottom	284	bid	0.89	80	0.70	12%
dry bottom	162	bid	0.5	70	0.73	10%
cyclone	480	bid	1.35	85	0.84	22%
cyclone	330	bid	2.4	68-91	0.92	29%

Table 2. High-Dust SCR Catalyst Requirements for Coal-Fired Service, By Boiler Type

Boiler Type	Size, MW	Uncontrolled NO$_x$ Emissions, lb/MMBtu	Removal Efficiency, %	Initial Catalyst Volume, m^3 (m^3/MW)	Annualized Catalyst Replacement, m^3 (%)
tangential	348	0.45	67	230 (0.66)	23 (10)
wall-fired	381	0.50	70	260 (0.68)	26 (10)
cell burner	600	1.00	85	600 (1.00)	120 (20)
cyclone	400	1.17	87	445 (1.11)	111 (25)
wet bottom	259	1.13	87	285 (1.10)	71 (25)
vertically fired	220	1.08	86	210 (0.95)	31 (15)

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Date: May 20, 1996   Total # of Pages: 4   + Cover

•MESSAGE•

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May 20, 1996

Perrin Quarles Associates, Inc.
501 Faulconer Drive, Suite 2-D
Charlottesville, VA 22903

Re: Comments of the Class of '85 Regulatory Response Group on
the Draft Report Entitled "Cost Estimates for Selected
Applications of NOx Control Technologies on Stationary
Combustion Boilers"

Dear Sir or Madam:

The Class of '85 Regulatory Response Group appreciates the opportunity to
review and comment on the draft report entitled "Cost Estimates for Selected
Applications of NOx Control Technologies on Stationary Combustion Boilers" that was
prepared by Bechtel Power Corporation and The Cadmus Group for the U.S.
Environmental Protection Agency. The Class of '85 does not have extensive comments
on the draft report, but would like to address one issue: the evaluated cost of retrofitting
selective catalytic reduction (SCR) technology on coal-fired boilers. The Class of '85
believes that the analysis is biased due to the use of an improper evaluation methodology,
optimistic cost estimates, and the failure to include likely capacity derates.

The draft report uses a power factor scaling methodology to derive estimated costs
for a system of one size based on known costs of a second system of a different size.
Power factor scaling is a generally accepted methodology for powerplant cost estimating,
since it addresses economies of scale associated with permitting, land, and other
infrastructure. However, the use of power factor scaling for SCR estimating is not
appropriate because SCR is not a powerplant, but a system component that inherently
lacks the assumed economies of scale. For example, unit costs (in $/lb or $/MW) of a
SCR catalyst for a 200 MW powerplant should be the same as for a 950 MW powerplant.
The net effect of using power factor scaling in the draft report was to reduce units costs
of SCR from $68/kW for a 200 MW powerplant to $39/kW for a 950 MW plant. The

DC01:102046.1

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Class of '85 does not believe that the SCR cost estimate of $39/kW for a 950 MW plant is credible but, instead, substantially underestimates the true costs of SCR retrofits.

Second, the cost history of domestic coal-fired SCR retrofits does not support the draft report's engineering cost estimate for typical coal-fired SCR retrofits when power factor scaling is dismissed from the evaluation. Commercial experience with SCR is summarized in Section 3.2.5.2 of Appendix A,[1] which discusses seven domestic coal-fired boilers where SCR has been installed. Five of these seven boilers were new construction and the costs of SCR at these boilers would not be representative of retrofit costs. The remaining two boilers, Mercer Station (Public Service Electric & Gas, 80 MW SCR retrofit with a SCR capital cost of $8 million) and Merrimack Station Unit #2 (Public Service of New Hampshire, 320 MW SCR retrofit with a SCR capital cost of $19 million) represent the entire United States database for coal-fired SCR retrofits.

While the Merrimack Station SCR retrofit costs were approximately $60/kW, the retrofit costs for Mercer Station were approximately $100/kW of installed SCR capacity. Although this cost difference could be explained using power factor scaling and these costs appear to conform with the draft report's retrofit SCR cost estimates as a function of unit size, the cost differences also could be due to ease of retrofit, design NOx removal, supplier profitability (or loss), or other factors. For example, Merrimack Unit #2's outdoor construction made it relatively easy to retrofit the SCR box into the proper location in the flue gas duct. For boilers constructed indoors, the Class of '85 expects that SCR installation costs would be significantly higher than the baseline cost used in the draft report. The Class of '85 believes that the final report needs to address retrofit SCR capital cost sensitivity in a realistic manner so as not to artificially minimize evaluated cost of NOx removal with SCR.

Lastly, the draft report specified a SCR system pressure drop of five inches water without addressing any capacity derates associated with fan capacity limitations. For boilers that were converted from bituminous to sub-bituminous coals, existing fan capacity to handle the increased flue gas pressure drop from SCR likely would require a plant capacity derate, which could ultimately accelerate the need to construct new electric capacity.

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[1]   Draft report entitled "Investigation of Performance and Cost of NOx Controls as Applied to Group 2 Boilers," at 3-15 to 3-17 (August 1995).

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      The Class of '85 Regulatory Response Group appreciates your consideration of its comments. For your information, a list of the members of the Class of '85 is enclosed. If you have any questions about these comments, please do not hesitate to contact us.

<div align="center">
Respectfully submitted,
</div>

William M. Bumpers
Debra J. Jezouit
Counsel to the Class of '85
   Regulatory Response Group

Encl.

DC01:102046.1

CLASS OF '85 REGULATORY RESPONSE GROUP

Arizona Public Service Company

Arkansas Electric Cooperative Corporation

Arkansas Power & Light

Central Louisiana Electric Company

Central & South West Services

City of Tallahassee

Consolidated Edison Company of New York

Dayton Power & Light

Duquesne Light Company

Entergy Services, Inc.

Florida Municipal Power Agency

Florida Power & Light

Gainesville Regional Utilities

Gulf States Utilities Company

Iowa Electric Light and Power Company

Louisiana Power & Light Company

Jacksonville Electric Authority

Lakeland Department of Electric and Water

Mississippi Power & Light

New Orleans Public Service Company

Niagara Mohawk Power Corporation

Northern States Power Company

Orlando Utilities

Pacific Gas & Electric Company

Wisconsin Power & Light Company

DC01:100216.1

with restricted furnace "height" or residence time will probably be limited to
the 40% reduction efficiency.

5.2.1. Coal-Firing. Accordingly, the assumption that natural gas reburn NOx
control cannot provide sufficient NOx control capability (minimum of 67%)
on coal to meet the targeted 0.15 lbs/MBtu level is consistent with the best
available experience and process design information.

5.2.2. Oil/Gas Firing. NOx reduction of 40-50% is required of natural gas
reburn to meet a 0.15 lb/MBtu emission limit. For the reasons delineated
earlier, this level of reduction may be beyond the capability of reburn on
oil/gas.

5.3. Selective Catalytic Reduction

The maximum NOx reduction cited for SCR (90%) is achievable only for
boilers firing exclusively natural gas, with essentially no significant oil backup
capability. As discussed previously, this is due to the absence of ash and
sulfur, which allow the use of small pitch, high activity catalysts that provide
significant surface area for NOx reduction. This high NOx reduction is not
considered feasible for coal and oil-fired applications, due to limits on
residual ammonia.

Conversely, the more common 80% NOx reduction is typical for coal-fired
applications, where residual ammonia must be maintained to 5 ppm or
below. The letter referenced in footnote 6 cites key reason why NOx
reduction for large, coal-fired boilers is nominally limited to 80%.

5.4. Selective Non-Catalytic Reduction

The maximum NOx reduction (50%) is probably achievable for boilers
approximating the 200 MW capacity size (as opposed to 930 MW), firing
natural gas, where the absence of sulfur allows relatively high (>5 ppm)
residual NH3. This high degree of NOx reduction is not considered feasible
for coal and oil-fired applications, which are probably limited to 25-30% NOx
reduction, unless unusual circumstances allow an increase in residual
ammonia (e.g. from 5-10 ppm to 10-20 ppm). The reasons for limiting NOx
reduction to 25-30% are addressed in Section 5.3.5 of the document referenced
in footnote 8.

Accordingly, the assumption that SNCR cannot provide sufficient NOx
control capability with coal to meet the targeted 0.15 lbs/MBtu level is
consistent with the best available experience and process design information.
For oil/gas firing, SNCR does provide sufficient NOx control capability
(40-50%) to meet a 0.15 lb/MBtu emission limit.

6.0. ADDITIONAL INFORMATION REQUIRED

The Bechtel/Cadmus report did not disclose many specific details of the analysis. The following discussion identifies basic assumptions and additional information necessary for a complete review of this report:

6.1. Economic Assumptions

The most significant economic assumption is remaining plant life, and the implications for capital recovery charge. The assumed capital recovery charge is particularly important in this analysis as capital-intensive SCR is the sole feasible technical option for coal-firing. Bechtel/Cadmus is requested to justify the 20 year period as an appropriate remaining lifetime.

As an alternative, several categories of plant age could be determining from FERC-derived information, and remaining lifetime selected accordingly. Although a significant fraction of units would be characterized by the 20 year remaining lifetime, a large fraction would also be represented by 15 and 10 year lifetimes. These units would be forced to incur a higher capital recovery factor.

6.2. Technical Assumptions

6.2.1. Site Features Of Reference Plants

The subject Bechtel/Cadmus report is silent on the specific source(s) used to construct the Bechtel database of reference plants; accordingly the statement from the Bechtel/Cadmus Group 2 report is assumed relevant. This statement (Appendix B, page B2-1) states "The design basis for each boiler plant was developed from the Bechtel in-house database for similar operating boiler installations. The design details established for each boiler are representative of typical boilers in the corresponding category".

EPA/Bechtel is required to share the specifics of the "similar boiler installations" used as input to the database, including layout drawings of the proposed typical plants.

6.2.2. SCR.

The following additional information is requested:

- Space velocity (e.g. quantity of catalyst required for NOx removal to meet 0.15 lbs/MBtu). Three separate SCR application cases should be addressed: coal-fired, fuel oil-fired, and natural-gas fired.

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- **SO2 Oxidation.** The report should identify the specified limit (if any) on the conversion of SO2 to SO3.
- **Boiler Economizer Bypass.** It is not clear if a boiler economizer bypass is included in the design to allow SCR operation at low load. (Presumably, SCR would be widely deployed under this scenario, and thus load-following units would require a boiler economizer bypass).
- **Site Physical Constraints.** The report should specify the fraction of the boiler population that must address unusual site features, that force significant equipment location. Under the present analysis, the fraction assumed appears to be zero, but this is not explicitly stated.

6.2.3. SNCR

SNCR NOx control performance for load-following applications is strongly dependent upon the ability to inject reagent effectively into flue gas in the correct temperature window. The proposed broad application of SNCR over the oil/gas boiler population suggests many candidate units would operate in load-following or "deep" cycling mode. What SNCR design concepts are assumed to vary reagent injection, such as the use of a multi-level injector assembly, and are these fully accounted for in the capital cost estimate? Also, what methods, if any, are assumed available to mitigate the impact of residual ammonia on fly ash or downstream equipment?

6.2.4. Reburn

The Bechtel/Cadmus evaluation assumes both coal and natural gas reburn are applicable to most boilers. As indicated by the document referenced in footnote no. 6, a certain fraction of the boiler population may feature a residence time distribution that eliminates reburn as a feasible technology. What assumptions has Bechtel Power made regarding residence time distribution for the boiler population? The text suggests, but does not state, the entire population is assumed to offer adequate residence time for reburn.

This assumption is important, as one vendor of reburn technology (Energy and Environmental Research Corporation) claims that NOx reduction is dependent on residence time available, and depending on NOx reduction desired, any boiler can deploy reburn. Thus, residence time assumptions are necessary to define the NOx reduction potential.

6.3. Economic Results

It is not clear how the results in Table 1-2 are employed to create Table 1-3. Bechtel is requested to define the methodology showing how the results in Table 1-2 are used to construct a mills/kWh cost, which is then translated into a levelized cost per ton.

May 23, 1996

Ms. Peggy Quarles
Perrin Quarles Associates, Inc.
501 Faulconer Drive
Suite 2-D
Charlottesville, Virginia

Dear Ms. Quarles:

Thank you for the opportunity to review the draft report entitled "Cost
Estimates for Selected Applications of NO_x Control Technologies on
Stationary Combustion Boilers." The following are our comments regarding
the draft report.

This report is comprehensive, and will serve a valuable function to
utilities attempting to select an appropriate NO_x reduction technology.
Due to the timely importance of the information and the influence of the
EPA documents regarding the selection of appropriate compliance
technologies, it is critical that the information within the report be
accurate and reflect current knowledge and experience. We would like to
address five critical issues that are not correctly represented in the
draft of this report:

1:   The report should assume the use of a catalyst management plan for
     SCR systems. The use of management plans reduce annual catalyst
     replacement costs by at least 65 percent. Not assuming the use of a
     catalyst management plan results in the inaccurate, nonrepresentative
     characterization of SCR costs.
2:   Published data reporting results of SNCR installations does not
     support the report's assumption that SNCR has a NO_x reduction
     capability of 50 percent. SNCR has demonstrated capability for
     reliably removing 20 to 40 percent NO_x reduction on small to medium PC
     boilers while maintaining ammonia slip in acceptable ranges.
3:   The report does not discuss or reflect potential economic impacts
     caused by the ammonia slip from SNCR systems such as forced outages
     and boiler load limitations. Experience has indicated that numerous
     SNCR installations need relatively frequent offline cleanings of the
     air heater when using SNCR with sulfur bearing fuels. Forced outages
     would be very expensive to accommodate especially during the summer
     peak season.
4:   The capacity factor used (65 percent) in the economic analysis of the
     report is too low. Likely target baseload units operating during the

    5 month "NO_x season" are likely to have very high capacity factors (85 to 95 percent) during this summer peak period. Assuming a misrepresentative value of 65 percent has a punitive effect on capital intensive technologies such as SCR.

5: Currently, this draft version appears very heavily biased towards SNCR and against SCR when discussing post-combustion NO_x control systems. We believe that it is misleading to imply that the installation of an SNCR system will reliably lead to 50 percent NO_x reduction with ammonia slip less than 10 ppm with no potential for significant detrimental impact on plant operation. Experience has demonstrated that this performance level to be the exception, not the rule.

We realize that it may be difficult to make significant changes to the report, but to not reflect these comments regarding SCR and SNCR performance and cost will mis-inform the users of this report with respect to the performance, cost, and plant impacts of post-combustion NO_x control technologies.
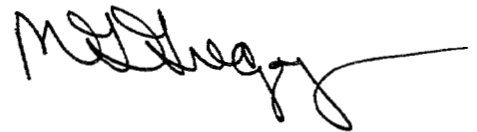
Further discussion of these comments is included as an attachment to this letter. If you have any questions regarding these comments, please call either me (913-339-7785) or John Cochran (913-339-2190). Our fax number is 913-339-2934. We look forward to discussing these comments with you.

    Sincerely,   Sincerely,

    John R. Cochran   Michael G. Gregory
    Manager-Air Quality Control Section NO_x Control Unit Leader

Attachment

cc: Ravi Srivastava - US EPA
   Volker Rummenhohl - STEAG
   Jeff Smith - ICAC

BLACK & VEATCH COMMENTS REGARDING DRAFT REPORT OF "COST ESTIMATES FOR SELECTED APPLICATIONS OF NO$_x$ CONTROL TECHNOLOGIES ON STATIONARY COMBUSTION BOILERS"

SCR CATALYST MANAGEMENT:
On page 3-1 of the draft report, the assumption is stated that "a catalyst management strategy is not used for this evaluation." This assumption is used for all boiler types. This is not a valid assumption considering the current design philosophy for SCR systems. The catalyst life guarantee is a measure of how long the catalyst will meet both NO$_x$ reduction requirements and ammonia slip limits. However, when the catalyst is unable to meet these requirements, there is still 70 to 80 percent of original catalyst activity remaining. A catalyst management plan will increase the effective utilization of this remaining activity. **To not assume a catalyst management plan results in inaccurate and non-representative economics to be presented for SCR.**

The design basis used for the tangential boiler example in this report has an average catalyst replacement value of 4,680 ft^3/yr. Therefore, it appears that the total catalyst volume is approximately 14,040 ft^3 (3 yrs x 4,680 ft^3/yr). Assuming a two-layer reactor design, 3 year catalyst life, 20 year remaining plant life, and no management plan, the total catalyst replacement would be a total of 12 layers (2 layers x 6 replacements) with a total cost of $32,760,000. Using the stated catalyst replacement cost of $350/ft^3 (Table 2-1), the annual cost catalyst replacement without a management plan is $1,638,000/yr ($350/ft^3 x 4,680 ft^3/yr).

In a modern SCR system (new or retrofit), at least one extra layer will be included in the reactor design for future addition of catalyst. This layer has a significant impact on the catalyst replacement cost over the life of the plant. An SCR system with the same catalyst volume (assume two layers) with a spare layer installed in the original design will have a much lower annual cost than an equivalent system with no spare layer. When the remaining active material within the catalyst is allowed to be utilized by adding catalyst rather than complete replacement, the total catalyst volume required over a 20 year life becomes 5 layers at a total cost of $12,285,000. **Use of a catalyst management plan leads to an average catalyst replacement cost of $614,250/yr, or only 37 percent of the cost without the management plan**[1]. This will have a significant impact on the operating cost and cost effectiveness of SCR measured in $/ton of NO$_x$ removed. **Accordingly, we strongly believe that the report should assume the use of a catalyst management plan.**

Even in the unlikely event of the inability to include a spare layer in the design, an effective catalyst management plan can be incorporated replacing individual layers. This also leads to substantial savings when compared to complete replacement at the end of catalyst life.

SNCR PERFORMANCE ON COAL FIRED BOILERS:

On page 3-2, the report states the assumption that "the SNCR system is designed to provide a 50 percent NO_x reduction from a baseline NO_x rate of 0.45 lb/MBtu." **Except for smaller CFB boilers, we have not been able to verify this performance capability on large coal fired boilers.** In Appendix A of this draft report (page 3-14 of "Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers"), the SNCR performance test results are summarized as follows: "In light of the ... data, a 30% to 40% NO_x reduction range can be recommended for sensitivity analyses." These SNCR performance results are based on the high NO_x inlet loading of Group 2 boilers. It is very unlikely that this performance can be exceeded with the relatively low inlet NO_x loading of a Group 1 boiler.

In the course of site specific NO_x evaluation studies we have conducted for numerous utilities (in excess of 10,000 MW), we have received quotes from the leading supplier of urea SNCR systems-Nalco Fuel Tech. These quotes are based on the best removal rates that they felt could be provided while maintaining a "reasonable" ammonia slip. The best of these performance quotes have been 50% reduction but with an unacceptably high ammonia slip value of 20 ppm. On these specific units, Nalco Fuel Tech indicated a maximum capability of 30% to 37% reduction when the ammonia slip is limited to 10 ppm or less. Even at an ammonia slip of 10 ppm, air heater fouling can be experienced when using SNCR with sulfur bearing fuels.

This is further evidenced by papers describing urea-based SNCR performance presented at the recent Institute of Clean Air Companies (ICAC) forum in Baltimore. NO_x reduction capabilities within the 30% to 40% range are described at two PC boilers. One of the papers[2] described a 112 MW boiler (with baseline NO_x emissions of 0.49 lb/MBtu) reported test results with NO_x reductions up to 50%, but normally operates at 40% NO_x reduction to meet regulatory requirements. The other paper stated that the capability of the SNCR portion of a catalyst/SNCR hybrid system could achieve a maximum NO_x reduction of 37% while burning coal.[3]

There is no evidence to support the design basis of this report that 50% reduction can be consistently met by SNCR while maintaining ammonia slip at 10 ppm or less. Although this performance may be met for short periods of time on small boilers, **the 50% NO_x reduction basis cannot be presented to the readers of this report as a design basis for all SNCR systems.** Quite simply, there is no experience with reliably obtaining these NO_x reduction levels on large coal fueled boilers. We believe that SNCR systems are very effective for installations on CFB's, and can be effective for NO_x reductions of 20% to 40% on small-to-medium sized PC boilers. However, the use of 50% as the design value of SNCR performance will skew the reader's performance expectations and artificially deflate relative life-cycle costs of the SNCR system compared to other NO_x reduction alternatives.

FORCED OUTAGES FROM SNCR OPERATION:

In the past several years, there has been much experience gained on post-combustion control methods. SNCR suppliers have been very active in test

programs, research projects, and actual commercial installations. The plant impact of SNCR systems has received mixed reviews. Although there are some reported results of SNCR systems operating on small boilers for one year without any significant problems on downstream equipment[2], **there is a very high risk of forced outages when using SNCR on coal fueled units.** One IPP with SNCR installed on eight 50 MW stoker boilers has had a great deal of trouble keeping their units operating because of the impacts of ammonia slip[4]. This installation describes air heater plugging, fabric filter bag fouling, and waste water treatment problems due to the high concentrations of ammonia. All this occurred while little or no ammonia slip was being measured at the stack, indicating that knowing ammonia slip at the boiler outlet is much more important than stack measurements. Also, another recent use of SNCR on a 140 MW eastern U.S. bituminous fueled pulverized coal unit has reportedly resulted in off-line air heater washings every 2 weeks or less despite an average ammonia slip of approximately 5 ppm. These forced outages would be very expensive to the utility requiring the purchase of power during the peak season.

These results indicate that the potential for problems due to SNCR systems cannot be ignored. A report issued by the EPA should address both the benefits and potential problems of each technology. For this report, that would involve adding a discussion of the potential downside of SNCR operation and fairly evaluating the likely costs for forced outages related to use of this technology. No similar likelihood for forced outages can be identified or justified for SCR systems.

LOW CAPACITY FACTORS IN ECONOMIC CAPARISON:
The draft report assumes a 65% capacity factor as the basis of the economic evaluation. We believe that this value does not accurately represent the units that a utility would consider for cost effective post-combustion NO_x reduction. Although a seemingly minor item, the capacity factor is a critical component of a utility's system-wide NO_x compliance evaluation. A large utility system will have units with a wide variety of capacity factors. In an effort to maximize the cost effectiveness of the control systems selected, these utilities will no doubt first concentrate on the base loaded units, with decreasing consideration as the capacity factor decreases.

This is especially true for the 5-month "NO_x season". The report uses 27% as the annual capacity factor for this time period (65% x 5/12). This time period by definition is the peak season for power generation, during which, 65% would probably not be considered acceptable to the system owners. To maximize generation, the utility would expect 85% to 95% capacity factors for its large generating units during this "NO_x season". The use of this higher factor would lead to an annual average capacity factor of approximately 37.5% (90% x 5/12). **The use of a higher, more representative capacity factor in your analysis will lead to a more accurate representation of SCR cost effectiveness.**

BIAS TOWARD SNCR:
We believe that the report's discussion of post-combustion NO_x control is heavily biased toward SNCR and away from SCR. The bias toward SNCR is evidenced by the complete lack of discussion of system variability and the associated high degree of supervision required to achieve acceptable performance. SNCR performance is critically affected by site specific design constraints and normal boiler operation transients such as load changes and heat transfer surface fouling/slagging. It is noteworthy that papers describing acceptable NO_x reduction capabilities indicate that changes in unit operation lead to large changes in urea utilization and difficulty in automatic control[2]. To imply that the installation of an SNCR system will reliably lead to 50% NO_x reduction with ammonia slip less than 10 ppm with no potential for significant detrimental impact on plant operation will mislead many readers into thinking it is the perfect high-efficiency control solution. In reality it also has the potential to achieve only 20% reduction while forcing frequent outages for equipment cleaning, lost fly ash sales, and limit the boiler's turn-down capability[5]. Please make sure that the report presents an accurate portrayal of SNCR capabilities and limitations which indicate that numerous recent SNCR installations have demonstrated unacceptable as well as acceptable performance. The user of this report must be informed that their actual results would probably fall somewhere within this SNCR performance spectrum.

The bias against SCR is demonstrated in paragraphs such as the third complete paragraph on page 2-2 in which catalyst volume requirements are described as "significantly large" and SO_3 conversion rates are described as "excessive". In addressing the catalyst volume requirements, rather than using "significantly large" (compared to what?), the report could state that **improvements in catalyst formulation and system design have reduced the amount of catalyst volume to 65% to 70% of the volume required by pre-1990 systems.** Also, SO_3 oxidation is not "excessive". The oxidation rate is a function of catalyst formulation, which is a design variable. In systems burning sulfur-bearing fuel, **the catalyst formulation can keep oxidation to levels to 1% or less, which is not excessive by any definition.**

REFERENCES:

(1) Cochran, John R.; Gregory, Michael G.; Rummenhohl, Volker; "SNCR, SCR, and Hybrid Systems Capabilities, Limitations, and Cost". Presented at the EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, May 16-19, 1995.

(2) Tsai, Thomas et. al.; "Living with Urea Selective Non-Catalytic NO_x Reduction at Montaup Electric's 112 MWe PC Boiler". Presented at the ICAC Forum '96, March 19-20, 1996; Baltimore, MA.

(more References on following page)

REFERENCES (Cont.)

(3)   Wallace, A.J.; Gibbons, F.X.; Roy, R.O.; O'Leary, J.H.; Knell, E.W.;
      "Demonstration of SNCR, SCR, and Hybrid SNCR/SCR NO_x Control
      Technology on a Pulverized Coal, Wet-Bottom Utility Boiler",
      Presented at the ICAC Forum '96, March 19-20, 1996; Baltimore, MA.

(4)   Hall, David; Bonner, Thomas J.; "SNCR Experience With Coal Fired
      Boilers and Fabric Filters". Presented at the ICAC Forum '94,
      November 1-2, 1994, Washington, D.C.

(5)   Gregory, Michael G.; Cochran, John R.; Rummenhohl, Volker; "The
      Impact of SCR and SNCR Systems on Plant Equipment and Operations".
      Presented at the ICAC Forum '94, November 1-2, 1994, Washington, D.C.

NALCO FUELTECH

Technology for a renewed environment ™

Vincent M. Albanese
Vice President
U.S. Sales and Marketing

May 7, 1996

Perrin Quarles Associates, Inc.
501 Falconer Drive, Suite 2-D
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Subject: Comments on Draft Report

Thank you for the opportunity to present comments on the draft report entitled "Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers". The stated purposes of the subject draft report were to develop costs for NOx control technologies to reduce NOx emissions from baseline to 0.15 lb/MBtu (the putative emissions limit after Phase III of the Ozone Transport Region's MOU is implemented), and to develop costs for NOx control technologies providing substantial NOx reductions beyond emissions limits mandated in Phase I for Group 1 boilers subject to acid rain NOx limits.

As a general comment, the treatment of capital costs may not appropriately reflect the cost to utility plants subject to NOx control regulations. If the subject report used the same methodology as Bechtel used in the referenced Group 2 boiler report to the EPA, the capital carrying charge utilized was a modest value of 0.115. Our recent experience in installing post-combustion NOx controls indicates carrying charges of 0.145-.200. As utilities prepare for deregulation and enforced competition in generation, the planning horizon for capital outlay has shortened considerably. By 1999 and 2000 the real financial world for utilities may be to carry capital for only 5 years. We encourage that cost estimates for NOx control be recalculated utilizing more representative higher carrying charges. Perhaps in recognition of the need to minimize capital outlay, the authors did well to point out that combinations of technologies might well be cost effectively applied, but that details for potential NOx reduction combinations were beyond the scope of the draft report.

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The technical data presented in the report seem to be an accurate recapitulation. However, two small comments do arise:

(1) Since one premise for all the data in the report is that LNB or combustion modifications have already been employed, the Gas Reburning data may need to be revisited in Table 1-5. The Acurex report entitled "Phase II NOx Controls for the NESCAUM and MARAMA Region" states cost effectiveness is significantly diminished for this add-on control because the NOx reduction is only 20% when LNB is already installed.

(2) In Section 3.1.1 regarding SCR, the statement "It is assumed that the existing plant setting allows installation of the SCR reactors between the economizer and the air heater without a need to relocate any major structure or equipment" is such an egregious leap it is better to qualify the statement with the admission that installation on a number of sites would be impossible or imprudently costly.

Of perhaps greater concern to NFT than any comments apropos to the subject report is there are several factual errors and misleading premises in the appendaged report "Investigation of Performance and Cost of NOx Controls as Applied to Group 2 Boilers" prepared for EPA by the Cadmus Group, Bechtel and SAI. Apparently this report served as a basis for EPA's proposed Group 2 boiler rule FR 1442, Jan. 19, 1996. NFT had provided both background information and formal comments on the proposed rule, but may have been disadvantaged by never having seen the Draft Group 2 report. NFT trusts this oversight will be rectified by incorporating the following comments to that report.

Section 3-1 Selection of Control Technologies for Evaluation

Report Statement: "For each Group 2 boiler type, this selection was based on availability of control technologies as established by at least one full-scale demonstration or commercial application."

NFT Comment: It is inappropriate to include thinly demonstrated technologies like coal reburn and combustion modifications on wet-bottom boilers, while maintaining that hybrid SNCR/SCR is outside the scope of the report. The successful demonstration of the technology on a Group 2 boiler at Public Service Electric and Gas along with the potentially broad applicability demand inclusion of the technology with greater focus than currently in the draft.

Another <u>caveat</u> regarding the basic premise of including full scale demonstrations is that demonstration costs are often far higher than application of the technology on a commercial basis. Overall scope is far more confined in commercial installations, and reagent prices will be more favorable.

Section 3.2.4.4 Factors Affecting Performance

Report Statement: "...SNCR process is capable of load following through adjustment of NSR".

NFT Comment: The statement is quite incomplete and does not represent the technology. It may be corrected to –

"SNCR process is capable of load following through automated control of injection level use, reagent dilution through the various injectors, and reagent flow rate at a given injection level(s), all of which usually changes NSR as load changes. The automatic control is setup on a feed-forward basis."

Sections 3.2.4 and 3.2.5 re Coal Sulfur Content

Report Statement: In describing the potential for ammonium salt formation in the flue gas, the authors state "...ammonia slip needs to be controlled in SNCR..." whereas in Section 3.2.5.4 regarding SCR, the authors state "...ammonia slip is controlled in SCR application to minimize..."

NFT Comment: The difference is subtle but the implication is SNCR doesn't control slip and SCR does. The fact is ammonia slip is an operational limitation of both technologies as it limits NOx reduction (for SNCR) or causes more capital expense (for SCR). U.S. Generating Company revealed pictures of NH_3 slip induced air heater pluggage in its ICAC Forum presentation entitled "Multiple Coal Plant SCR Experience - a. U.S. Genco. Perspective". NFT asks that the subject of ammonium salt formation and subsequent air heater deposition be treated in a more equitable tone.

Appendix B, Section 4.4 SNCR Application

Report Statement: "The source of urea was assumed to be the NOxOUT reagent commercially supplied by Nalco Fuel Tech."

NFT Comment: NFT does not supply urea or any other reagents used in air pollution control systems. The urea at the referenced plant was supplied by one of five commodity suppliers of urea that offer appropriate quality material to be used in conjunction with the NOxOUT process.

Section C.2.4.5 Reagent Cost

Report Statement: "A significant portion of the SNCR O.& M. costs is tied to the consumption of the chemical reagent. Therefore, the annualized cost of an SNCR application is particularly sensitive to the market price of the reagent used."

NFT Comment: This is not borne out by the sensitivity graphs on pg. B4-42. The parameter to which SNCR cost is more sensitive is % NOx reduction to be achieved by the SNCR system.

NFT will be happy to supply further comments if required. Please feel free to call me at (708) 983-3254.

Sincerely,

Vincent M. Albanese

VMA/mjb

cc: S.C. Argabright
     R.A. Johnson
     J.E. Hofmann

May 24, 1996

REC'D MAY 2 8 1996

Mr. Ravi Srivastava
Environmental Engineer
Acid Rain Division
U.S. EPA
401 M Street, SW
Mail Code 6204J
Washington, DC 20460

Dear Mr. Srivastava,

Thank you for the opportunity to comment on the Bechtel report on NOx control costs
for utility boilers. I forwarded the report to our engineering folks, and they reviewed it
in detail. In general, the report is quite reasonable and complete. Some of the cost
estimates are lower than we have used; some are higher. These comparisons are
attached, along with some specific suggestions for improving the report.

We look forward to your final rule on NOx emission controls for Title IV sources. If
you would like to discuss our comments, please call Mr. Robert H. Thomas at (860) 665-
3793.

Sincerely,

OS3422 REV. 8-95

ATTACHMENT

‚Ħ Asset Management has reviewed the EPA draft report entitled "Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers". The final version of this report will be used by EPA to evaluate the costs of retrofit NOx controls applicable to fossil fuel-fired boilers in the U.S. The report makes the assumption that the controls will be required to limit NOx emissions to 0.15 lb/MMBtu and includes essentially all basic boiler designs and oil/gas/coal fuels.

The technologies evaluated in the report were limited to Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR) and Gas Reburning. To evaluate the report, cost projections were compared to the costs that we have experienced in the NU system installing similar equipment and to NU cost estimates prepared for 1999 NOx compliance.

˜eneral report comments are immediately below, followed by comments on the ˙ort details, typos, and specifics.

GENERAL COMMENTS

o   The report recognizes that some "Hybrid systems" are more cost-effective for certain applications. These could include SNCR with a shallow-bed catalyst or additional combustion controls with SCR. However, these options were not in the scope of analysis.

o   SNCR alone was not considered for coal units because the limit of 0.15 is considered beyond the reduction capability of SNCR alone from a baseline of 0.45-0.50.

o   Only natural gas as a reburn fuel is considered applicable because coal or oil reburn fuel does not have enough reduction capability.

       The SCR retrofit capital costs assume no allowance for relocating any existing structures or equipment. In general this is a bad assumption.

o   The report does not mention including costs for wastewater treatment facility modifications which might be required to handle SCR ammonia plant wastes and washwater wastes.

o   The coal unit sulfur content assumed in the report is only 0.8 wt%. Bisulfate formation on air heaters due to the SCR/ammonia combination could become a much greater factor in downtime costs and air heater capital work if the higher sulfur coals were assumed. SO3 formation from the SCR on higher sulfur coals can accelerate downstream corrosion and produce opacity plume/acid fallout problems. These conditions should be factored into the report cost estimates for coal.

o   The levelized carrying charge factor assumed is only 60% of the value NU would use.

o   The anhydrous ammonia cost assumption is about 20% less than experienced at Merrimack.

  o   No mention is made as to disposal cost of used SCR catalyst, and ash

disposal costs are about 33% less than NU's experiences.

o   The reported SCR capital costs for oil or oil/gas units are about 1/3 lower than the latest NU estimates.

o   The reported SCR capital costs for coal units are about 20-25% lower than NU would estimate.

o   The reported SNCR capital costs for oil or oil/gas units are more than 50% higher than NU estimates.

o   Natural gas assumptions for oil unit reburn should reflect the higher pricing more representative of non-interruptible gas contracts (typically 20% of total unit heat input).

o   Large variations in NOx reduction equipment capital cost estimates on many of NU's smaller units can be seen in the asymptotic scaling factors which the report applies to units less than 200 MW. The same effect can be seen for levelized annual costs.

o   The report summary table for oil and gas fuels shows that SNCR is 50% or less of the cost of SCR on units of NU's size. This cost comparison is generally true for low and high capacity assumptions and on a basis of $/KW or $/Ton NOx.

DETAIL COMMENTS

_   Table 1-2 should have a note that these are "$1995" and that the formulas for capital cost are "$/kw" and not "$".

o   Table 1-3 should have a note that the baseline NOx levels are as shown in table 1-1.

o   Table 1-4 should have a note reflecting that the SNCR assumption for coal units is that 0.15 lb/MMBtu cannot be achieved.

o   Section 2.1, first para.--Seems to erroneously refer to table 1-2.

o   Sect. 2.1, sec. para.--0.45 and 0.50 are in reverse order, respectively.

o   Sect. 2.1, third bullet--Adding natural gas reburn to a pressurized unit can be a safety hazard. The report should mention limiting application factors such as this.

o   Sect. 2.1, fourth bullet--The cost and NOx reduction assumptions for for SNCR should explain whether or not in-furnace lances are included.

o   Table 1-5 should have a note that the reduction percentages assume some baseline NOx levels.

o   Table 2-1 should show a more realistic carrying charge factor, higher anhydrous ammonia costs, higher ash disposal costs, and SCR disposal costs.

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August 7, 1996

Dwight Alpern
Environmental Protection Agency
501 3rd Street, N.W.
Washington DC 20001

Re: Request for Meeting Between UARG and EPA Consultants

Dear Dwight:

Thank you for your letter dated June 26, 1996 regarding the request by UARG's consultants to meeting with EPA's consultants to discuss technical issues on NO_x control technologies. These meetings were and are needed to resolve questions raised by the Agency's reports and analyses in the § 407 NO_x rulemaking, the Ozone Transport Assessment Group (OTAG) discussions, and other regulatory forums. As you know, UARG wanted to settle the outstanding issues in these proceedings as expeditiously as possible, and it is unfortunate that the Acid Rain Division did not allow its consultants to meet with UARG's consultants regarding technical issues related to the § 407 rulemaking in May. We also understand that where technical issues relate to matters other than the § 407 NO_x rulemaking, EPA will agree to a meeting on technical issues only if:

1. Our clients are not represented at the meeting by counsel;

2. UARG's consultants are limited to raising questions regarding the need for additional information or explanation to understand the EPA consultant's analysis or conclusions;

3. UARG's consultants may not raise any questions that reflect disagreement with technical assumptions, analyses, or conclusions in EPA technical reports; and

4. Any questions that UARG's technical consultants want to raise (and that can be raised under the guidelines described above) must be submitted to EPA in writing prior to the meeting.

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We find this a very curious approach to developing a technically sound basis for NO_x control initiatives. As you know, CAA § 307(d)(3) requires disclosure in connection with proposed Agency actions of "the factual data" on which a proposed action is based, as well as "the method used" in obtaining and analyzing the data. Given that meaningful comment is not possible unless there is full disclosure of the facts and methodology on which the Agency relies, UARG and others have traditionally worked closely with EPA technical staff to develop and to understand the basis for proposed regulatory actions. This has often involved meetings that include EPA and UARG technical consultants, in order that the technical experts on each side have the benefit of each others' expertise and professional judgment. For these reasons, we are confused as to why EPA would want to close these lines of communication. This does not appear to be a step designed to foster either good science or sound policy.

The enclosed comments by Ed Cichanowicz are specifically directed to Bechtel's draft "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," which apparently is intended for use in OTAG. Many of the data and methodology issues raised in the Cichanowicz comments directly relate to the proposed § 407 NO_x rule, which uses a companion Bechtel report for its basis. These questions go both to the need for complete disclosure of data and methodology, and to the technical merit of specific analytical approaches and assumptions. Among these questions, which are detailed in the Cichanowicz report, are the following:

- how is the remaining plant life determined;

- what are the specific boilers in Bechtel's "in-house data base" whose design details are assumed to be representative of typical boilers in each category;

- what do the layout drawings look like of the "similar boiler installations" that are assumed by Bechtel to represent this nation's entire boiler population;

- what space velocities are assumed for each fuel in SCR applications;

- what limits are specified for the conversion of SO_2 to SO_3 in SCR applications;

- what assumptions are made for boiler economizer by-passes in the design of SCR applications;

- what proportion of the boiler population has unusual site features that would force significant equipment relocation in SCR applications;
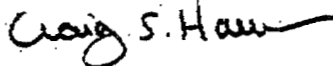
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- what SNCR design concepts are used to account for deep cycling of oil and gas-fired units;

- what is the distribution of residence time in the boiler population and how does this affect the feasibility and cost of reburn applications; and

- how are the results in Table 1-2 employed to create Table 1-3?

Resolution of these issues is critical to sound cost estimates for OTAG and a sound § 407 rule. The fact that there remain outstanding technical questions in the § 407 rulemaking illustrates the lack of meaningful opportunity for the regulated industry to comment on EPA's proposed rule. We therefore ask that EPA reconsider the restrictions that it has placed on the exchange of technical information between the Acid Rain Division consultants and UARG consultants.

Sincerely,

F. William Brownell
Craig S. Harrison

Enclosure

cc: Air docket A-95-28

Summary Of Comments For
the Draft Report Prepared for U.S. EPA
by Bechtel/Cadmus

"Cost Estimates For Selected Applications Of
NOx Control Technologies
On Stationary Combustion Boilers"

Comments Prepared for
The Utility Air Regulatory Group

by

J.E. Cichanowicz

July 31, 1996

Summary Of Comments For
the Draft Report Prepared for U.S. EPA
by Bechtel/Cadmus

Cost Estimates For Selected Applications Of
NOx Control Technologies
On Stationary Combustion Boilers

Comments Prepared by

J.E. Cichanowicz

1.0 OVERVIEW

The subject report, entitled "Cost Estimates For Selected Applications Of NOx Control Technologies On Stationary Combustion Boilers" (March 1996), prepared for EPA by Bechtel Power Corporation (under subcontract to Cadmus) addresses the cost of broadly applying advanced and presently evolving NOx control options to the national boiler population. This report is distinguished from previous NOx control technology assessments as it addresses the specific task of bringing the entire inventory of coal-, oil-, and natural-gas fired boilers into compliance with an extremely stringent NOx level of 0.15 lbs/MBtu. This analysis presumes all coal-, oil-, and natural-gas fired boiler have already successfully applied combustion controls for Title IV or RACT purposes. The analysis is based on background information and a database of control technology developed by Bechtel for use in a previous evaluation for EPA through Cadmus, described in the August 1995 report "Investigation Of Performance and Cost of NOx Controls as Applied to Group 2 Boilers", hereafter referred to as the Bechtel/Cadmus Group 2 Report.

The key assumption of this analysis is the use of a power-law scaling relationship to project capital cost over a wide range of generating capacity, and process conditions. This critical assumption has been addressed in earlier supplemental comments prepared for UARG, regarding the proposed Group 2 boiler NOx limits[1]. To reiterate, these cost evaluations employ a simple power-law relationship which can introduce significant error if the range in generating capacity over which cost is projected is too large. Generally, the range of extrapolation should be within a factor of two so as to NOT require changes in process design; otherwise an inappropriate design is considered as the cost basis.

---

[1] See Section 3.1 of "Supplemental Comments for Group 2 Boiler NOx Emission Limits, addressing Cost Evaluation Methodology And Technical Applicability of Selected NOx Control Options", prepared by J.E. Cichanowicz for UARG, June, 1996 (Attachment 1).

Within the present study, I noted trends in capital cost estimates that are counterintuitive and thus suggest errors in extrapolating cost information from the Bechtel database. Specifically, the results suggest SCR capital cost for cyclone-, cell-, and conventional wall- and tangential-fired boilers are similar ($~69/kW), despite the significantly higher boiler NOx production rates from the former two categories. (Under the premises of this study, cyclone and cell-fired boilers are assumed to produce 220% and 140% of the NOx from pulverized coal-fired boilers). This anomalous trend is most notable at 200 MW, but persists at higher generating capacity.

Similarly, the capital cost for reburn and SNCR were projected with a power-law relationship of the same form, from generating capacities of 200 MW to 900-1000 MW. Capital cost estimates developed for deploying these technologies at 200 MW appear consistent with utility industry experience and recent process design information. These capital cost estimates are: for SNCR, $16-18/kW on coal and $9-11/kW on oil/gas applications; for reburn $19-22/kW on oil/gas. (Reburn was not judged capable of providing the requisite NOx reduction capability on coal). However, projecting these capital costs to large generating capacity (960 MW for oil/gas and 1030 MW for coal) produces extremely low values. Accordingly, I suggest the power-law relationship overcredits economies of scale inherent, and process designs developed for large capacity process conditions must be more complex, and thus costly.

Generally, the Bechtel/Cadmus analysis accurately represents NOx reduction capabilities of the candidate technologies. For coal, I concur that the only NOx control technology capable of consistently meeting a 0.15 lb/MBtu limit from the boiler baseline NOx production rates cited is SCR; reburn and SNCR cannot provide the minimum of 67% NOx control capability consistently over the entire boiler population. For oil- and natural gas-fired applications, up to three of these technologies may be capable of meeting the 0.15 lb/MBtu limit from the assumed boiler NOx production rates (0.30 and 0.25 lbs/MBtu, respectively): SCR, SNCR, and reburn. However, RACT implementation between various states is not consistent, and the national boiler population may contain a significant number of units that produce NOx in excess of the assumed rates. Also, reburn may be limited to 35% NOx reduction for those cases where LNB and OFA have already been deployed to achieve the 0.30 and 0.25 lbs/MBtu limit. SNCR may be limited to 35% NOx reduction on sulfur bearing fuels due to formation of ammonium sulfates/bisulfates on downstream equipment. Subsequently, I recommend that SNCR and reburn are not capable of meeting the 0.15 lb/MBtu limit for all oil- and gas-fired units.

Finally, additional information is requested from EPA and Bechtel/Cadmus defining key assumptions and premises of the analysis. Examples of these

are: basis for 20 year remaining life given the diversity of boilers in the national population, specification of space velocity for SCR, design concepts assumed to provide load-following capability for SNCR, residence time assumed for the boiler population for reburn, and specifics of calculating levelized cost and cost per ton from information presented in summary tables.

2.0 GENERAL METHODOLOGY AND ECONOMIC PREMISES

This section addresses the methodology and basic assumptions inherent to the analysis. Most of these issues have been treated in earlier UARG comments and thus will not be addressed in detail; rather the previous comments will be referenced as appropriate.

<u>Assumption Of RACT-Equivalent Boiler NOx Production Rates.</u> The subject Bechtel/Cadmus analysis assumes the entire boiler population has deployed combustion NOx controls, contributing to a reduction in cost for post-combustion or other advanced technology. This assumption is valid for most cases; however two issues must be addressed:

- Oil-fired and gas-fired boilers. Most of the boiler inventory, particularly those units located in the northeast and near ozone non-attainment areas will probably emit at the 0.30 and 0.25 lbs/MBtu rate assumed for this study. However, a significant inventory of units in the southeast may not be in regions of non-attainment; these units will likely produce NOx much higher than the assumed levels. *Recommendation: Recognize and account for an approximately 20% of the oil/gas-fired boiler inventory that will not be operating at RACT NOx limits.*

- Cyclone/cell-fired boilers. Title IV Group 2 boiler NOx production emission rates of 0.94 and 0.68 lbs/MBtu are proposed for cyclone-fired and cell-fired boilers, respectively. However, the boiler baseline NOx production rates for the cost evaluation are assumed to be 1.17 and 1.0 lbs/MBtu, respectively. These higher boiler NOx production rates increase capital cost, and also lower cost per ton of NOx removed. *Recommendation: Assume cyclone- and cell-fired boilers (and other Group 2 boilers as appropriate) emit NOx at the Title IV proposed limit.*

<u>Absence of Detailed Equipment Lists.</u> UARG has previously cited the importance in developing specific equipment lists as a necessary prerequisite to developing meaningful cost information. An industry position paper addressing SCR cost (initially issued by UARG and EPRI in 1993, and revised

in 1994 for UARG and the National Mining Association[2]) stressed the need to develop layout drawings defining the location of equipment as necessary for a realistic cost estimate. EPA recognized this requirement, and directed Bechtel to develop specific equipment lists (although layout drawings were not prepared) for the "reference" cases developed for each boiler type in the Bechtel/Cadmus Group 2 Report.

However, the scope and ambition of the subject Bechtel/Cadmus analysis - to project advanced NOx control technology cost for the national utility boiler population - eliminates the possibility of preparing detailed equipment lists for the candidate plants. Not all regulators support this position, as the Air Director for New Hampshire proposed such a unit-by-unit detailed assessment in OTAG as feasible[3]. Despite the claims of this one state regulator, developing equipment lists for the majority of generating units in the national boiler population (or even within the subset of OTAG) is not feasible or possible under almost any conditions. *Recommendation: EPA should recognize the uncertainty regarding any results from such an ambitious study, and assign an appropriate margin for error.*

A minimum requirement for the ambitious objectives of the Bechtel/Cadmus study is to (a) develop specific process designs (based on equipment lists/layout drawings) for each category of boiler, and (b) limit the use of power-law derived costs to only small capacity changes.

<u>Assumption Of Accessible Site Conditions.</u> Although not explicitly stated in the subject Bechtel/Cadmus Report, Bechtel and the EPA Acid Rain Division staff have stated that fundamental to their analysis is the assumption that plant sites do not feature any unusual physical constraints or access issues that would significantly elevate retrofit cost[4]. This approach presumes the acquisition of capital equipment and modest installation requirements comprise the primary cost of retrofit. "Scope Adder" items have been included in the Bechtel/Cadmus analysis, but these do not always reflect a complete and adequate scope of activities.

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[2] See page 12 of "Factors Affecting SCR Capital Cost For Coal-Fired Utility Boilers", prepared by J.E. Cichanowicz for UARG and NMA, June, 1995 (Attachment 2).
[3] New Hampshire's Air Director suggested those involved in OTAG discussions eliminate any uncertainty in control technology cost by developing estimates of NOx control technology cost for 250 of the largest units in the OTAG region on a unit-by-unit basis. This strategy, which he described as not "terribly onerous", was proposed to derive cost information as an alternative to the "blue sky, global stuff" prepared by UARG. This statement is extremely insightful, as it illustrates the lack of appreciation that most regulators have for the complexity of issues regarding retrofit of NOx control technology (See Air Daily, May 23, 1996).
[4] Personal communication, EPA Acid Rain Division's Ravi Srivastava and Bechtel Power's Sikander Khan, with J.E. Cichanowicz, October, 1995.

The subject Report does not define the "study boilers" that serve as the basis for the analysis. *Recommendation: EPA should further define the boilers that served as "baseline" for the analysis, disclosing site features, balance-of-plant equipment, and the anticipated process impacts.*

As the subject Bechtel/Cadmus Report is silent on this issue, and derives data heavily from the Bechtel/Cadmus Group 2 Report, I examined background information presented in the latter report for insight. As noted in Appendix B, page B2-1, "...the design details established for each boiler are representative of typical boilers in the corresponding category". Although it is encouraging that Bechtel Power has used a database with "typical" boilers, it must be recognized that by definition "atypical" boilers are excluded from this cost evaluation.

Recommendation: EPA should recognize a certain fraction of boilers feature site conditions presenting a greater challenge than assumed for this analysis, and thus will incur higher cost. Accordingly, some boilers may require a premium for further "Scope Adders" beyond that assumed by the Bechtel database.

<u>Selected Use Of EPRI TAG-Derived Cost Methodology.</u> The subject report, similar to the Bechtel/Cadmus Group 2 Report, claims that EPRI Technical Assessment Guide (TAG) methodology is fully adopted as the basis for estimating cost.

As noted in earlier UARG comments, this statement is not completely true. Most significantly, the cost for financing capital equipment and construction during the construction period - referred to as Allowance For Funds Used During Construction (AFDC) - was ignored. As stated in earlier comments, the construction period for SCR is anticipated to be one year - and thus ignoring AFDC is inappropriate. This leads to underestimating capital costs by nominally 5%.

In addition, the remaining plant lifetime and subsequent capital recovery factor may not be appropriate. EPA assumes a 20 year remaining lifetime, and assigns a capital recovery factor from the 1993 TAG of 0.127. (This capital recovery factor is appropriate for a 20 year recovery period, and consistent with TAG recommendations). However, the 20 year recovery period, although appropriate for newer units, may be optimistic for many older units, particularly Group 2 boilers. *Recommendation: As the Bechtel/Cadmus study is intended to address the national boiler population, an aggregate representation of 17-18 years - and a corresponding capital recovery factor of 0.14 - may be more appropriate.*

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3.0. COAL-FIRED APPLICATIONS

3.1. SCR Capital Cost Estimates (Table 1-3)

The capital cost analysis for SCR applied to coal-firing is predicated on a scaling relationship (a) derived from <u>one base case plant design</u> developed for 200 MW capacity, and (b) assuming the identical process design developed for 200 MW applies to large capacity units (500 MW and greater). As stated in supplemental comments regarding the Bechtel/Cadmus Group 2 (see footnote 1), the use of scaling relationships over a wide generating capacity range violates the basic premises under which these relationships are developed, and can invalidate the results.

Specifically, a recent article by Remer[5] contains a final section entitled "Limitations And Potential Errors" which discusses the use of cost vs. capacity relationships, and proper scaling factor (referred to as 'R' value):

> *"The use of the cost-capacity equation and the R factors presented in this article can simplify the complex task of estimating equipment costs for air pollution control. Users of these factors must be careful, however, not to extrapolate outside the range for which the R value is determined. The cost found using this method are ball park estimates; when more exact costs are required, actual vendor quotes should be sought."*

This reference clearly cautions regarding the use of the power law relationship outside of the range for which the basic process design was developed.

Due to either misuse of the scaling relationship and/or other assumptions in this analysis, capital cost estimates developed for SCR applied to coal-fired plants are not internally consistent, or are they logical with basic design trends. Specifically, first consider that SCR capital cost reported for wall-fired boilers ($69.38/kW) exceeds that projected for tangential-fired boilers ($66.82/kW). Presumably, this trend is due to higher boiler NOx production for wall-fired boilers (0.50 vs. 0.45 lbs/MBtu) requiring greater catalyst quantity to meet the 0.15 lbs/MBtu limit. Consistent with this logic, capital cost for cyclone and cell-fired units should significantly exceed capital cost for both wall- and tangential-fired boilers, regardless of capacity, as NOx production rates from cyclone and cell-fired boilers (assumed by the Bechtel/Cadmus

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[5] A recent article in *Chemical Engineering* entitled "Air Pollution Control: Estimate The Cost Of Scale-Up" (November, 1994, by Remer et. al.) addressed the concerns for employing the conventional scaling relationship (Attachment 3).

analysis to be 1.17 and 1.00 lb/MBtu) will require SCR reactors with significant catalyst quantity.

Contrary to this well-recognized design trend, the Bechtel/Cadmus analysis reports SCR capital cost for cyclone and cell-fired boilers to be approximately equivalent to wall-fired boilers at 200 MW, despite the significant difference in boiler NOx production. Even at the largest boiler capacity evaluated (1030 MW) there is a negligible difference in capital cost between cell-fired and wall/tangential-fired boilers, and only a 12% premium for a cyclone application.

This observation suggests a flaw in the evaluation methodology. The only conditions under which SCR capital cost for cyclone and cell-fired boilers could be equivalent to wall- and tangential-fired boilers are either/or (a) ability to relax the residual ammonia limit for cyclone and cell-fired units, or (b) reduction in cost of the non-catalyst (e.g. ancillary) components. Neither items (a) or (b) appear likely. Accordingly, SCR cost is probably underpredicted by the power-law scaling relationship for cyclone boilers. *Recommendation: EPA should recognize the potential for errors in capital cost, due to the selection of the "reference" site, and extrapolation from the Bechtel database over generating capacity and process conditions. These results further support UARG-suggested capital estimates (~$18/kW higher).*

A second issue to be addressed is the ability of SCR to provide in excess of 80% NOx reduction for coal-fired applications. Regarding high NOx reduction, several factors prevent achieving greater than 80% NOx reduction without incurring significant capital cost penalties: these are maintaining strict (<3 ppm) limits of residual NH3 in flue gas, achieving uniform NH3/NO mixing, managing maldistribution in flue gas velocity due to flow path, and relatively low boiler NOx production rates. The potential barriers these issues present to achieving a NOx limit of 0.15 lb/MBtu have been described in previous OTAG deliberations[6]. *Recommendation: Except for the case of exclusive natural gas firing, assign SCR a NOx reduction capability of 80%.*

Finally, the assumption that no unusual site features exist that complicate retrofit of equipment has been discussed in Section 2 of this document. *Recommendation: EPA should recognize that some units will require additional equipment for retrofit, and assign a cost accordingly.*

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[6] See letter from Hunton & William's Craig Harrison to Brock Nicholson, dated June 17, 1996 (Attachment 4).

3.2. SNCR Capital Estimates (Table 1-4)

For 200 MW capacity, the capital cost estimated for SNCR ($16-18/kW) is similar to that reported for most commercial installations (e.g. PSE&G/Mercer, Atlantic Electric/Englund, New England Power/Salem Harbor). The relatively low capital cost estimate developed for SNCR applied to 1030 MW ($6-7/kW) could be a consequence of inappropriately employing the power law scaling relationship. Specifically, the significant increase in physical distance across the boiler over which reagent must be mixed could require increasing the number of SNCR injectors, or deploying high momentum lances in lieu of low energy wall injectors. In addition, the greater mixing distance probably requires an increase in the sophistication and complexity of the reagent process control system. Any of these modifications will increase the capital cost and are not accounted for in the scaling relationship derived by Bechtel/Cadmus. *Recommendation: EPA should recognize the increase in complexity of SNCR technology with greater generating capacity will negate any economies of scale, and employ the capital requirement developed at 200 MW for all capacities.*

4.0. OIL/NATURAL GAS FIRED APPLICATIONS

4.1. SCR

For both oil and natural gas-firing, SCR capital cost estimates (Table 1-3) for 200 MW appear consistent with industry experience at Southern California Edison, San Diego Gas & Electric, and the Los Angeles Department of Water & Power. There is no experience with SCR capital cost at 930 MW by which to compare Bechtel/Cadmus estimates. Similar to the discussion for coal-firing, the use of the power-law extrapolation without considering the need for a change in process design can underpredict capital cost estimates.

As stated in the 1995 SCR cost white paper, the importance of exclusive firing a boiler with natural gas in contributing to low SCR capital cost cannot be discounted. The referenced document describes how exclusive use of natural gas - relegating fuel oil backup operation 1-2 weeks per year at most - allows the use of extremely small pitch, high vanadium content SCR catalyst. Consequently, proportionally small quantities of catalyst are required, with space velocities for these applications exceeding 25,000 1/h (compared to 3500-5000 for coal-fired SCR). Clearly, the five-fold reduction in catalyst quantity compared to coal-fired application is key to minimizing SCR capital cost for such applications. *Recommendation: EPA should recognize SCR cost projected is most applicable to natural gas-fired applications,; EPA should include a cost premium for applications to sulfur-containing fuel oil.*

Comments: Cost Estimates For Selected Applications Of
NOx Control Technologies On Stationary Boilers
Draft Report Prepared March 1996

4.2. SNCR, Reburn

Projected capital cost for SNCR applied to oil-fired and gas-fired boilers (Table 1-3) at 200 MW capacity ($9-11/kW) is reasonably consistent with industry experience (e.g. LILCo/Port Jefferson Station). The capital cost projected for SNCR at 930 MW ($4/kW) appears artificially low; it is possible scaling issues are not properly treated. As stated for coal-fired SNCR applications, achieving the targeted NOx reduction may require increasing the number of reagent injectors, or employing the high momentum lance-type injectors.

For reburn, there is no domestic commercial experience with oil and natural gas-firing at any capacity by which to judge cost. (It will be assumed that oil-fired stations are equipped with natural gas on-site, and will not require additional investment for natural gas access). Reburn capital cost for 200 MW capacity ($19-22/kW) for oil and gas is probably accurate, due to the relatively compact and simple furnace arrangement compared to coal-firing. However, estimates of reburn capital cost at 930 MW ($11-13/kW) could be underpredicted as the scaling relationship does not recognize the need to increase the complexity of the system to accommodate greater mixing distances for reburn fuel.

Recommendation: For both SNCR and reburn, the potential for requiring increased complexity for either reagent or reburn fuel injectors with higher capacity may negate any economies of scale. Thus, capital requirement developed at 200 MW should be applied to all capacities.

Also, as noted in the following section, NOx reduction capability for reburn on oil- and gas-fired boilers to meet the proposed 0.15 lbs/MBtu limit may not be adequate, due to prior deployment of aggressive combustion controls such as low NOx burners and overfire air. Further process enhancements to increase NOx reduction may be necessary, elevating cost.

5.0 NOx CONTROL PERFORMANCE

NOx control performance for candidate technologies as assumed in the Bechtel/Cadmus Report, and summarized in Table 1-5, appear reasonable, with several exceptions. The following further clarifications are offered:

5.1. Coal Reburn

The maximum NOx reduction for coal reburn on coal-fired boilers (50%) is probably achievable for boilers approximating 200 MW generating capacity (as opposed to 930 MW capacity), featuring sufficient furnace "height" or residence time, and firing relatively high volatility coals.

Conversely, boilers of larger capacity (e.g. significantly greater than 200 MW), with restricted furnace "height" or residence time, and firing relatively low volatility coal will probably be limited to the 35% reduction efficiency.

The significant impact of boiler design criteria on NOx removal capability for coal-reburn was evidenced by the analysis conducted by Babcock & Wilcox (B&W) on residence time requirements for cyclone boilers; results were highlighted in a letter from B&W to the Acid Rain Division's L. Kertcher[7]. Specifically, this analysis showed that no more than 35% NOx reduction can be anticipated for a significant portion of the cyclone boiler inventory. A similar trend may characterize pulverized coal-fired boilers, with a significant fraction of the inventory not providing the necessary residence time for reaction.

Accordingly, the assumption that coal reburn NOx control cannot provide sufficient NOx control capability for coal-fired boilers (minimum of 67%) to meet the targeted 0.15 lbs/MBtu level is consistent with the best available experience and process design information.

5.2. Natural Gas Reburn

The maximum NOx reduction (60%) is potentially achievable for boilers approximating the 200 MW capacity size (as opposed to 930 MW capacity), and with sufficient furnace "height" or residence time.

One critical unresolved issue regarding natural gas reburn performance is the NOx reduction capability subsequent to application of combustion controls such as LNB and overfire air technology. As discussed in the draft topical report addressing NOx control technology for the OTAG Control Options Workgroup[8], most demonstrations concerning natural gas reburn addressed uncontrolled boilers that had not previously installed LNB or OFA technology. As addressed on page 24 of the report referenced in footnote 8, results from the sole demonstration of natural gas reburn on a coal-fired boiler suggest LNB contributes to reburn NOx reduction. These results suggest NOx reduction with gas reburn applied to boilers that have already retrofit LNB and OFA may be limited to 35%.

In addition to concerns regarding NOx reduction subsequent to RACT controls, boilers of larger capacity (e.g. significantly greater than 200 MW), and

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[7] Letter from J.M. Piepho (Babcock & Wilcox) to L.F. Kertcher (EPA Acid Rain Division), October 27, 1995 (Docket item A-95-28, Attachment 5).
[8] "Electric Utility Nitrogen Oxides Reduction Options For Application By The Ozone Transport Assessment Group", Prepared for the OTAG Control Technologies & Options Workgroup, January 1996 (Attachment 6).